What's in a name?

2009 AltaGas Annual Report

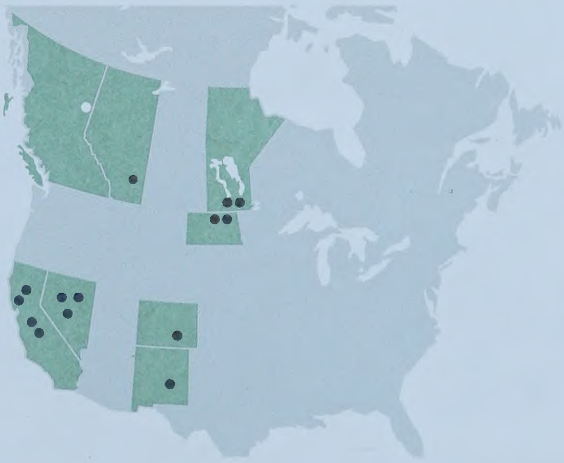
Bear Mountain Wind Park, Dawson Creek, British Columbia

More than you think... this is AltaGas

Our business lines are geographically diversified across Canada and include natural gas extraction and transmission, distribution and storage, energy services and power generation, as well as the natural gas gathering and processing AltaGas has historically been known for.

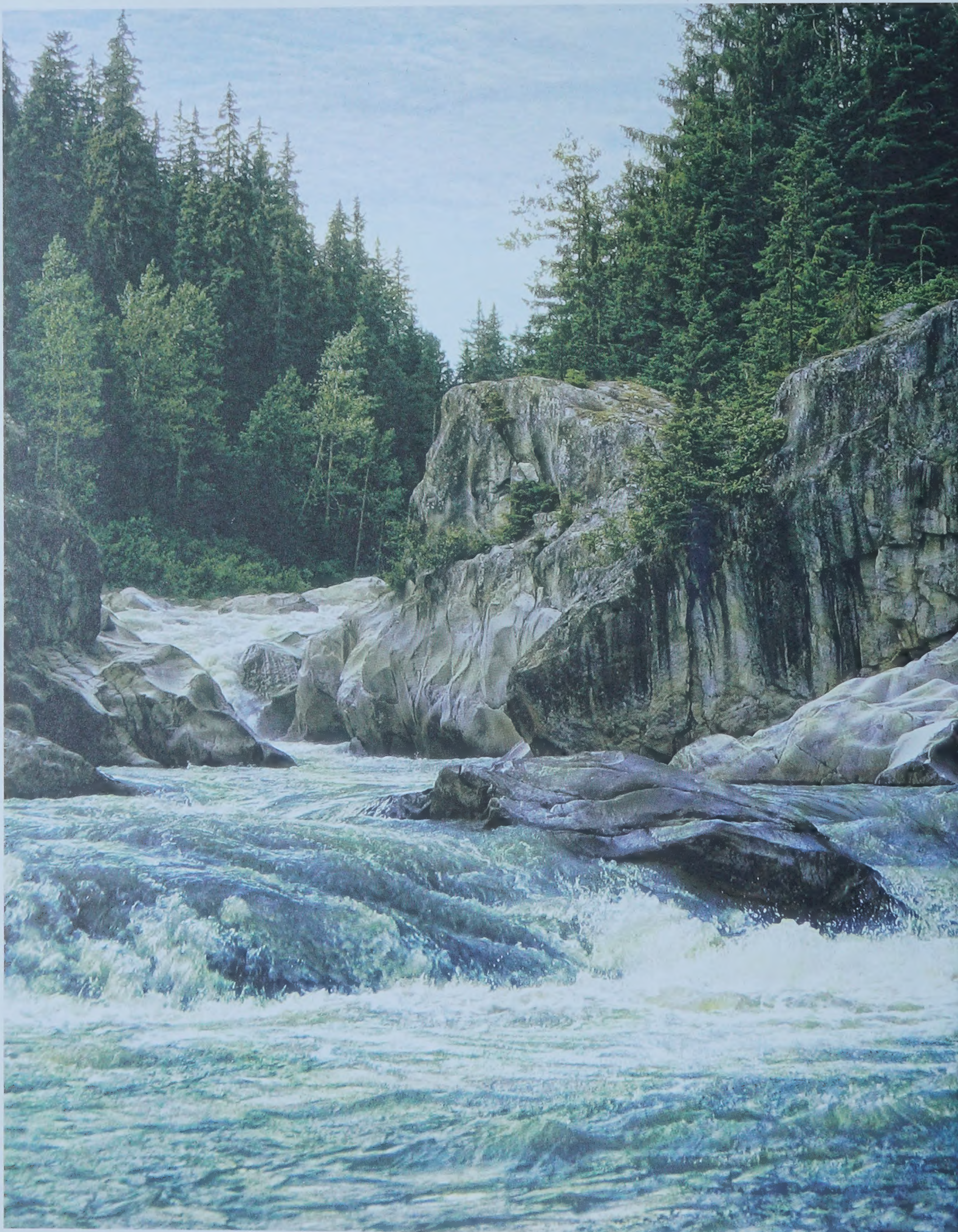
The 102-MW Bear Mountain Wind Park in northeast British Columbia is the most recent addition to AltaGas' power business. The $200 million wind park, commissioned on budget and ahead of schedule, is the first facility to deliver wind power into B.C.'s electricity grid.

Our wind development portfolio includes 1,500 MW of projects in various stages of development across western North America. They are located in markets with favourable regulatory regimes, high emission standards and strong consumer and government demand for clean power. We are meeting this demand with projects such as Bear Mountain Wind Park.

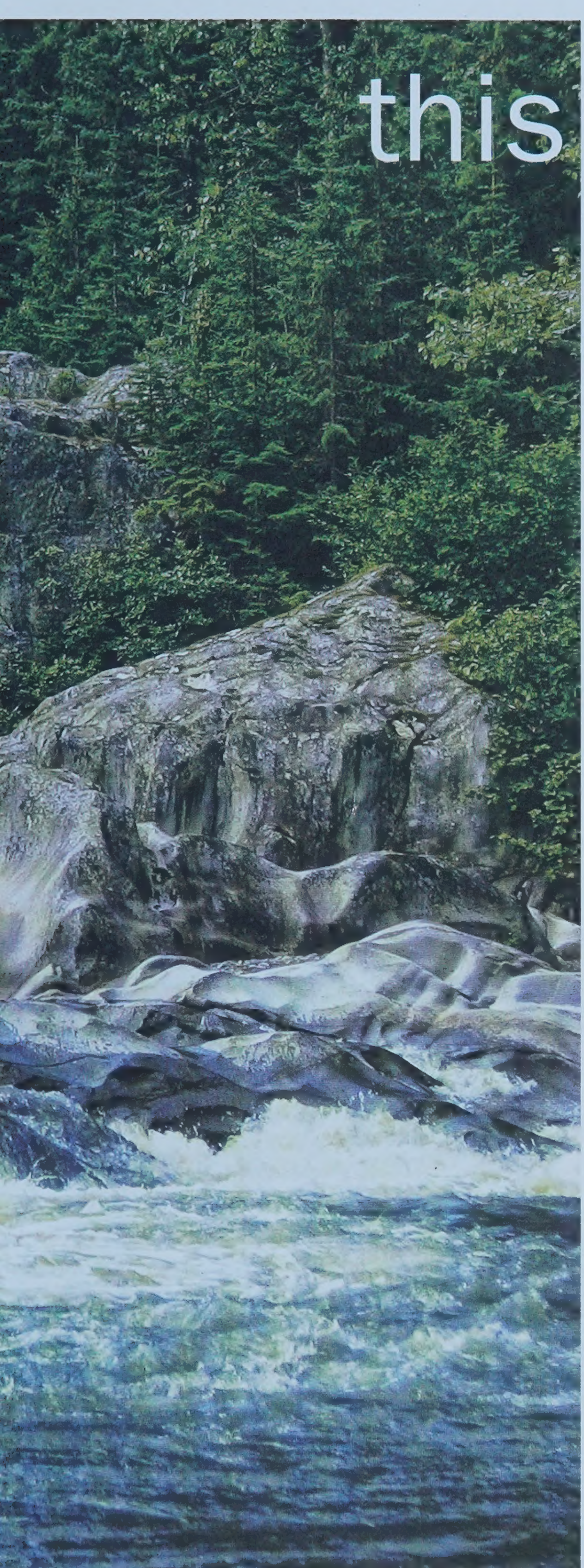


Current wind generation capacity	102 MW
Wind capacity under development	
Canada	500 MW
United States	1,000 MW

Refer to map on page 27 in the MD&A for more detail.



Forrest Kerr run-of-river project, British Columbia

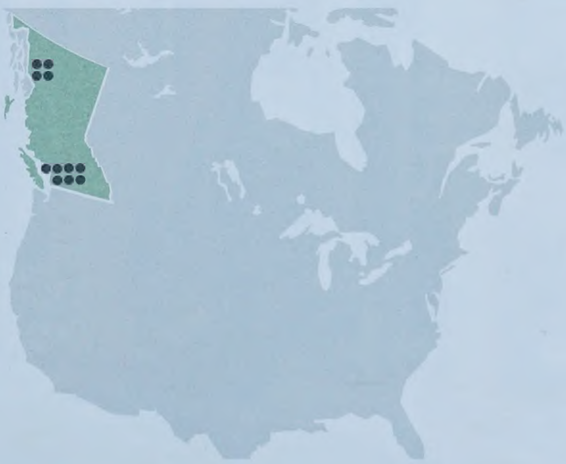


this is AltaGas

Our existing power portfolio is being supplemented with clean sources of power, such as wind, run-of-river hydro, geothermal and gas-fired generation. We pursue projects that meet certain requirements: natural resources with access to transmission infrastructure and for construction and in jurisdictions with favourable regulatory and market conditions.

Today AltaGas has approximately 400 MW of run-of-river hydroelectric projects under development in British Columbia, as well as a 25 percent interest in an operational 7-MW facility. The Northwest projects, which include the 195-MW Forrest Kerr development, will bring clean, renewable energy to communities and industry in northwest B.C.

We invest in renewable energy because it's consistent with our strategy of holding long-term, high-quality assets with good returns. Our goal is to diversify our power portfolio by fuel source, geography and contract type. Renewable projects expand our business, ensuring its long-term sustainability while reducing our emissions intensity. Secured by long-term contracts, these projects will provide clean energy to consumers in return for stable cash flow.



Northwest projects	277 MW
Log Creek and Kookipi Creek	20 MW
Early-stage developments	100 MW

Refer to map on page 27 in the MD&A for more detail.

Joffre extraction facility, Alberta

this is AltaGas

Founded in 1994 with the vision of building the first major independent Canadian midstream company, AltaGas has evolved into a diversified operator and developer of gas and power infrastructure. Today our gas business gathers, processes, transports, distributes, stores and markets natural gas and natural gas liquids (NGLs), touching more than 2 Bcf/d of gas from coast to coast to coast in Canada.

In response to producer demand, we are pursuing opportunities to expand and build gathering and processing facilities in prolific plays in northeast B.C. and northwest Alberta, such as the Montney and Doig.

The planned Harmattan Co-stream project will optimize our existing Harmattan Complex by using spare capacity to process rich, sweet natural gas and extract the valuable ethane and NGLs.

The natural gas distribution business serves more than 72,000 customers in Alberta, Nova Scotia and the Northwest Territories. These utility assets offer significant organic growth potential. In Nova Scotia, consumer demand for natural gas heating is expected to grow, and organic growth will expand the rate base in Alberta.

AltaGas' Sarnia gas storage facility has been operational since June. Given our energy services expertise, long-term storage assets fit our strategy. We are pursuing additional storage opportunities, including a development in Michigan.

Extraction capacity	1.6 Bcf/d
NGL production capacity	86,000 Bbls/d
Processing capacity	1.2 Bcf/d
Transmission capacity	
Natural gas	554 Mmcf/d
Natural gas liquids (NGLs)	151,600 Bbls/d
Natural gas distribution business rate base	$254.8 million

Refer to map on page 21 in the MD&A for more detail.

New Grad Program, Calgary head office

this is AltaGas

We seek and train the best people, for they are the future of AltaGas. We provide opportunity, challenge and competitive compensation, creating a positive work environment that motivates people to build careers with our company.

AltaGas' New Grad Program offers recent graduates exposure to various aspects of AltaGas' business. Each New Grad is assigned a mentor at the senior management level to share ideas and knowledge related to career planning, the energy industry and AltaGas. This intensive and demanding work experience program helps prepare New Grads for more challenging roles with AltaGas in the future.

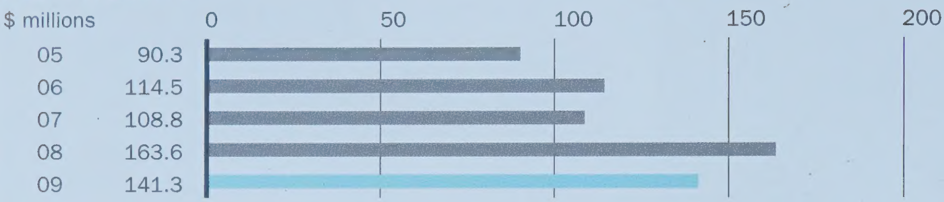
In 16 years AltaGas has grown from 20 employees and $3.5 million in assets to a workforce of more than 900 and an asset base of $2.6 billion. We remain committed to health, safety and the environment, our people and the community.

AltaGas consistently earns high scores on safety audits and supports initiatives that help make our employees and the communities in which they live safer. We generously contribute to community initiatives and also pursue long-term commitments that impact our partner organizations and the communities they support.

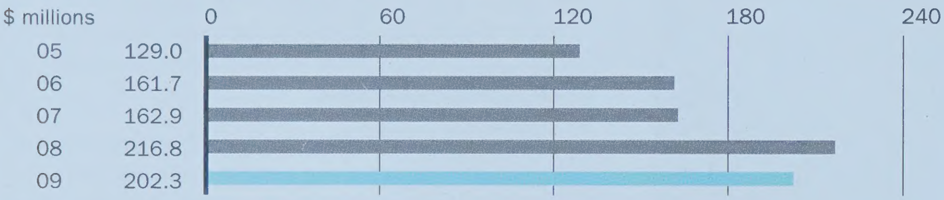
AltaGas Office Locations

AltaGas has the financial discipline and flexibility to pursue growth opportunities, while continuing to deliver earnings growth and strong, stable returns to investors.

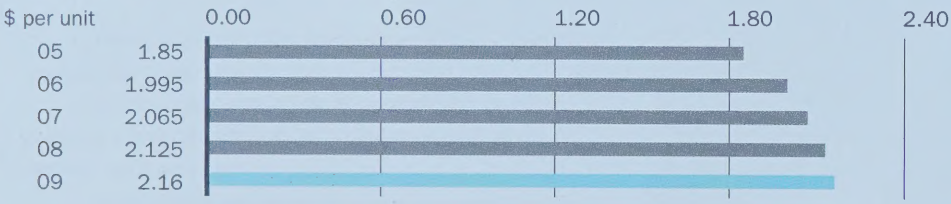
Net Income



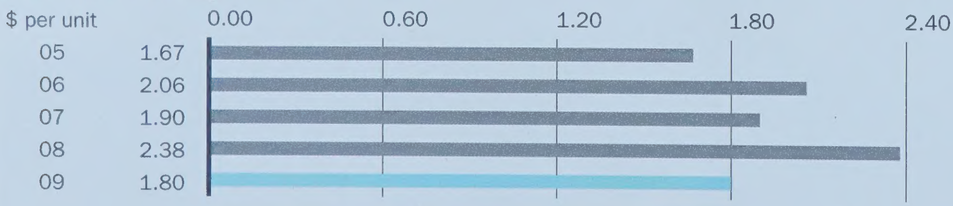
Funds from Operations



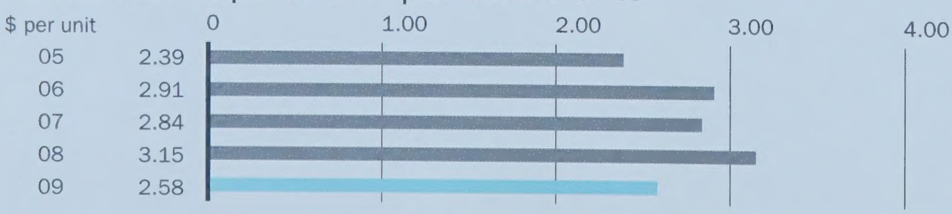
Distributions Declared per Unit



Net Income per Basic Unit



Funds from Operations per Basic Unit



this is AltaGas

Financial Highlights

$ millions except as indicated

	2009	2008	2007	2006	2005
Revenue	1,268.3	1,816.8	1,428.4	1,362.6	1,502.3
Net revenue [1]	456.6	476.5	324.0	318.9	296.9
EBITDA [1]	248.4	256.4	173.7	173.1	155.5
Net income	141.3	163.6	108.8	114.5	90.3
Net income before tax [1]	142.5	162.0	114.7	113.4	89.0
Total assets	2,629.1	2,132.3	1,172.7	1,109.6	1,068.3
Total debt	1,014.7	582.0	220.7	265.5	269.0
Debt as a percent of total capitalization (%)	49.2	37.8	27.4	33.4	36.0
Funds from operations [1]	202.3	217.1	162.9	161.7	129.0
Distributions declared [2]	170.2	147.1	118.6	110.8	100.0

$ per basic unit

EBITDA [1]	3.16	3.73	3.03	3.12	2.88
Net income	1.80	2.38	1.90	2.06	1.67
Net income before tax [1]	1.81	2.35	2.00	2.04	1.65
Funds from operations [1]	2.58	3.15	2.84	2.91	2.39
Distributions declared per unit [2]	2.16	2.125	2.065	1.995	1.85

1. Non-GAAP financial measure. See discussion beginning on page 33 in the Management's Discussion and Analysis.
2. Distributions declared do not include special distributions in the form of AltaGas Utility Group Inc. shares. Declared additional distributions of $4.2 million ($0.076 per unit) in August 2007 and $29.3 million ($0.54 per unit) in November 2005.

and this is AltaGas

What's in a name? More than you think. Our name reflects where we've been, but our vision is far greater. Spend some time with us and we'll show you our plans for the future.

While our strategy is still to invest in low-risk, high-quality assets that process, move and store energy, we are finding these assets in new and exciting places – over $2 billion in projects in the next five years.

We are leveraging these assets to provide consistent, long-term growth with an eye to the future. The best days are ahead of us as we successfully deliver the energy society needs in a sustainable way.

The Report

David W. Cornhill
Chairman and Chief Executive Officer

Letter to Investors

AltaGas focuses on investing in low risk, high-quality assets that create, move and hold energy. Today we are finding these assets in new and exciting places: wind power in California, run-of-river hydroelectric power in northwest British Columbia, natural gas distribution in Nova Scotia and storage in Michigan.

I am proud of AltaGas' past and excited about its future.

AltaGas has come a long way in 16 years, while consistently delivering strong returns to investors. Founded in 1994 with the vision of building the first major independent Canadian midstream company, AltaGas has evolved into a diversified energy infrastructure operator and developer.

Strong Balance Sheet

- Investment-grade credit ratings
  - One of two Canadian companies to receive credit rating upgrades in 2009
  - S&P and DBRS both upgraded AltaGas to BBB stable
- 49.2 percent debt-to-capitalization, within target range of 45 to 50 percent

Strong Cash Flow

- EBITDA of $248 million
- Long-life, low-risk assets
- Strong contractual underpinning
- Hedged cash flows

Strong Liquidity

- Credit facilities totalling $816 million, with more than $260 million available at year-end
- Strong banking group
- Good access to capital markets
- Annual DRIP of $34 million

Today our business lines are geographically diversified across Canada and include natural gas extraction, transmission, distribution and storage, energy services and power generation, as well as the gathering and processing AltaGas has historically been known for.

Today, every aspect of our business is strategically positioned for growth. Looking to the future, I see many exciting opportunities. Our best days are ahead of us as we successfully deliver the energy society needs in a sustainable way.

2009 Performance

AltaGas performed well in 2009, reporting [illegible] earnings and cash flow comparable to 2008's record year. It was a year of challenges and opportunities, and we faced them head-on. Both the gas and power businesses reported solid results as AltaGas managed its assets to ensure stable cash flow in a volatile and weak economy.

Although weak gas prices affected drilling activity in the Western Canada Sedimentary Basin (WCSB) and prompted some producers to shut-in gas wells, the gas business performed strongly. The completion of the Sarnia gas storage facility and the acquisition of the natural gas distribution business combined with the strong performance of our extraction and transmission assets resulted in higher earnings than 2008.

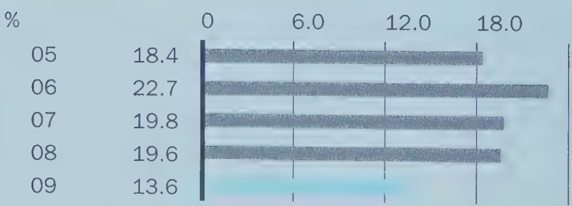
The power business reported solid results. Despite weakness in Alberta spot prices, the segment was protected by AltaGas' disciplined risk management policies.

AltaGas is committed to having a strong balance sheet and the financial flexibility necessary to support its operations and growth strategy. We made significant strides in 2009 to further bolster our balance sheet through financing initiatives, including debt and equity offerings. Our disciplined strategy was rewarded with credit rating upgrades to BBB stable from S&P and

2010–2015: $2 Billion in Growth Projects

- Harmattan Co-stream project
- Gas processing opportunities in northwest Alberta and northeast B.C.
- Natural gas distribution rate base growth and acquisition opportunities
- Gas storage facilities in Michigan
- Wind and run-of-river power projects

Return on Equity



DBRS. Today we have the financial flexibility to pursue projects that support our strategy of investing in long-life energy infrastructure assets.

Successful Execution of Our Growth Strategy

AltaGas added stable revenue-generating sources with the completion and commissioning of two major development projects and the addition of two accretive acquisitions. Bear Mountain Wind Park made history in October, when it became British Columbia's first operational wind park. It was commissioned ahead of schedule and on budget and marks the completion of AltaGas' first renewable energy development. The 102-MW wind park is backed by a 25-year fixed price contract with BC Hydro and will add significantly to earnings in 2010.

In June we completed the Sarnia gas storage facility, our first infrastructure asset in Ontario. This long-term asset is our first move into gas storage, but we are also pursuing additional development opportunities.

In late 2009 we welcomed back AltaGas Utility Group and acquired the remaining 75.1 percent of Heritage Gas Limited. The utility business fits our strategy as we move forward. These long-life assets underpinned by rate-regulated revenues strengthen our overall business profile and diversify cash flows.

The Future Is Bright

With $2 billion in organic growth projects currently under development, the best days lie ahead for AltaGas. We continually evaluate opportunities to grow our business, while remaining within our disciplined financial targets. Our focus is long-life, low-risk infrastructure that provides stable, long-term cash flows. Growth opportunities include expansions of existing AltaGas assets, new developments and business or project acquisitions. In the long run, growth will be split evenly between gas and power.

A diverse power portfolio—natural gas, wind, run-of-river hydroelectricity, geothermal—will provide stability for AltaGas in the long run. We invest in renewable energy because it's consistent with our strategy of holding long-term, high-quality assets with good returns. These projects will expand our power business and ensure its long-term sustainability while reducing our emissions intensity.

Following corporate conversion in the second half of 2010, AltaGas will continue to implement its strategy and provide investors with a balance between income and growth. Regardless of business structure, AltaGas remains committed to delivering strong returns to investors.

As a corporation, AltaGas expects to pay a dividend between $1.10 and $1.40 per share on an annual basis. This payout is expected to align AltaGas with its corporate peer group and enable it to pursue the strong investment opportunities available.

Our 900-person-strong workforce is dedicated to serving our customers and delivering good returns to our investors, and I would like to thank them for their outstanding achievements in 2009.

We had a successful year, and I am confident that we will continue to create value in 2010 and beyond.

On behalf of the Board of Directors,

David W. Cornhill
Chairman and Chief Executive Officer
March 2, 2010

Corporate Governance

David W. Cornhill
Chairman and Chief Executive Officer

Member of the EOHSC

Allan L. Edgeworth
Director

Independent director; Member of the AC and EOHSC

Myron F. Kanik
Lead Director

Independent director; Chair of the GC and Member of the HRCC

Hugh A. Fergusson
Director

Independent director; Member of the AC and EOHSC

Denis C. Fonteyne
Director

Independent director; Chair of the EOHSC and Member of the HRCC

Daryl H. Gilbert
Director

Independent director; Member of the AC and Chair of the HRCC

Robert B. Hodgins
Director

Independent director; Chair of the AC and Member of the GC

David F. Mackie
Director

Independent director; Member of the GC and HRCC

Neil McCrank
Director

Independent director; Member of the GC and EOHSC

The members of the Board of Directors of AltaGas General Partner Inc. are elected by the Trust at the direction of the unitholders to manage or supervise the management, business and affairs of the Trust. It is our responsibility to ensure that the interests of unitholders and other stakeholders are properly represented. To that end, the Board of Directors has assumed responsibility for stewardship of the Trust and has developed standards and procedures for its operations that meet a high standard of governance. We regularly review the activities of the Trust with a view to ensuring its business affairs are conducted appropriately, with the honesty, integrity, transparency and accountability that unitholders expect. We are committed to continuing to direct the activities of the Trust to those high standards.

The annual meeting provides AltaGas' executives with the opportunity to communicate the Trust's goals and strategy to unitholders. The meeting offers unitholders the chance to hear first-hand from management and to understand AltaGas' strategy for seeking to continually increase unitholder value and grow the Trust. The Board of Directors and AltaGas' management team encourage you to attend the annual meeting either in person in Calgary or through the live Webcast, which can be viewed at www.altagas.ca.

The annual meeting will be held at 3:00 p.m. MDT on Thursday, June 3, 2010 at The Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta.

On behalf of the Board of Directors,

Myron F. Kanik
Lead Director

AltaGas believes that good governance improves performance and benefits all unitholders and is therefore committed to a high standard of governance. The following is a summary of the Trust's Governance Practices. A more detailed description of the Trust's practices can be found in the Trust's Information Circular filed on the SEDAR system at www.sedar.com.

Statement of Gc

Mandate of the Board

The Board of Directors of the General Partner exercises overall responsibility for the management and supervision of the affairs of the Trust. This includes the appointment of the Chief Executive Officer and other senior officers of AltaGas Ltd. and AltaGas General Partner Inc., approval of their compensation and monitoring of the Chief Executive Officer's performance.

The Board of Directors also reviews and approves the annual strategic plan. Key objectives, as well as quantifiable operational and financial targets and processes for the identification, monitoring and mitigation of principal business risks are incorporated into the annual strategy review.

The Board of Directors ensures that a process is established that adequately provides for succession planning, including the appointment, training and monitoring of senior management.

Board Composition

The Board currently comprises nine Directors, eight of whom are independent. David W. Cornhill, Chairman and Chief Executive Officer of AltaGas, is the only member of the Board of Directors who is also a member of management.

Board Committees

The Board has four standing committees: Governance (GC); Audit (AC); Environment, Occupational Health and Safety (EOHSC); and Human Resources and Compensation (HRCC). The GC, AC and HRCC are composed exclusively of non-management, independent Directors. The EOHSC includes a majority of independent, non-management Directors, as well as the Chairman and Chief Executive Officer of AltaGas. Each of the committees has a Board of Directors-approved mandate that prescribes its composition and responsibilities.

Governance Committee

The GC reviews Board performance and provides recommendations for improvement to the Board with respect to all aspects of governance. The GC identifies individuals qualified to become members of the Board of Directors and recommends them for election, as well as reviewing and recommending Director compensation and formally assessing the effectiveness of the committees and the Board on an annual basis. The GC is also responsible for the orientation and education of new members and continuing development of existing members.

Audit Committee

The AC consists of four independent and financially literate Directors who oversee the Trust's financial reporting process on behalf of the Board of Directors. The AC reviews and provides recommendations to the Board of Directors on the annual and interim financial statements, as well as examining the completeness and accuracy of the Trust's financial reporting and the adequacy of its risk management processes and internal controls for financial reporting and disclosure.

The AC approves the appointment, terms of engagement, provision of non-audit services and proposed fees of the independent auditor. At every meeting, the AC has the opportunity to meet with the external and internal auditors without management present.

The Chair of the AC is Robert B. Hodgins, previously Chief Financial Officer of Pengrowth Energy Trust, Treasurer of Canadian Pacific Limited and Chief Financial Officer of TransCanada Pipelines Limited. Mr. Hodgins has the strong financial background crucial to this role.

Environment, Occupational Health and Safety Committee

The Trust is committed to being a steward of the environment and to the health and safety of its employees.

The EOHSC is responsible for reviewing, reporting and making recommendations to the Board of Directors on the Trust's policies and procedures with respect to the environment and occupational health and safety.

Human Resources and Compensation Committee

The HRCC reviews, reports and provides recommendations to the Board of Directors on the compensation of the Chief Executive Officer, the appointment and compensation of senior corporate officers, succession plans, the compensation policy for all other employees and the approval of all grants of trust unit options.

AltaGas is committed to operating its businesses in an ethical manner. In 2006, AltaGas adopted a Code of Business Ethics, a copy of which can be viewed on our Website.

Management's Discussion and Analysis

The Management's Discussion and Analysis (MD&A) of operations and Consolidated Financial Statements presented herein are provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Income Trust (AltaGas or the Trust) as at and for the year ended December 31, 2009 compared to 2008. This MD&A dated March 2, 2010 should be read in conjunction with the accompanying Consolidated Financial Statements and notes thereto of the Trust for the year ended December 31, 2009.

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect" and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. Specifically, such forward-looking statements are set forth under: "Strategy"; "Gas – Description of Assets – Capitalizing on Opportunities"; "Gas Outlook"; "Power – Description of Assets – Capitalizing on Opportunities"; "Power Outlook"; "Global Capital Market Conditions"; "Growth Capital" and "Corporate Outlook".

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Trust's current views with respect to future events based on certain material facts and assumptions and are subject to certain risks and uncertainties, including without limitation changes in market competition, governmental or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in the Trust's public disclosure documents.

Many factors could cause the Trust's or any of its segment's actual results, performance or achievements to vary from those described in this MD&A, including without limitation those listed above as well as the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this MD&A herein should not be unduly relied upon. These statements speak only as of the date of this MD&A. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified as cautionary statements.

Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for the purposes other than for which it is disclosed herein.

Additional information relating to AltaGas can be found on its Website at www.altagas.ca. The continuous disclosure materials of the Trust, including its annual MD&A and Consolidated Financial Statements, Annual Information Form, Information Circular, Proxy Statement, material change reports and press releases issued by the Trust, are also available through the Trust's Website or directly through the SEDAR system at www.sedar.com.

2009 Highlights

Completed two major capital projects: the 102-MW Bear Mountain Wind Park in northeast B.C. and the 5.3 Bcf Sarnia storage facility in Ontario (AltaGas owns 50 percent).

Acquired ownership in three natural gas distribution businesses serving more than 72,000 customers in Alberta, Nova Scotia and the Northwest Territories. These acquisitions enhanced fourth quarter results.

Weak gas prices combined with volatility in the capital markets impacted drilling activity in the Western Canada Sedimentary Basin, prompting some producers to shut in gas wells.

Completed several financing initiatives – $100 million equity issue, $250 million credit facility and $300 million in medium-term notes – and received credit rating upgrades from both S&P and DBRS.

ALTAGAS INCOME TRUST

The material businesses of the Trust are operated by AltaGas Ltd., AltaGas Operating Partnership, AltaGas Limited Partnership, AltaGas Pipeline Partnership, Taylor NGL Limited Partnership (Taylor), AltaGas Utility Group Inc. (Utility Group), as well as AltaGas Energy Limited Partnership and ECNG Energy L.P. (collectively, the operating subsidiaries). The cash flow of the Trust is solely dependent on the results of the operating subsidiaries and is predominantly derived from interest earned on loans to the operating subsidiaries and from dividends or returns of capital from equity interests held within the Trust structure.

AltaGas General Partner Inc., through its Board of Directors, the members of which are elected by the Trust at the direction of the unitholders, has been delegated by the trustee of the Trust to manage or supervise the business and affairs of the Trust. AltaGas Ltd. provides all management, administrative and operating services to the Trust and its subsidiaries.

VISION

AltaGas' vision is to be a leading North American energy infrastructure company with a focus in Canada and the northern and western United States. To achieve its vision, AltaGas capitalizes on its solid base business, operational expertise and financial strength and focuses on increasing the value and profitability of its existing assets and growing and diversifying its business. With more than $2 billion in organic growth projects under development over the next five years, AltaGas is well on its way to realizing its vision.

OVERVIEW OF THE BUSINESS

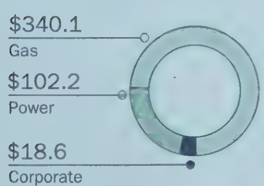
AltaGas is a natural gas and power infrastructure business with physical and economic links along the energy value chain. AltaGas' efficient, reliable and profitable assets, market knowledge and financial discipline have resulted in the creation of long-term value for its investors. AltaGas focuses on maximizing the profitability of its assets, providing services that are complementary to its existing business, and growing through the acquisition and development of additional energy infrastructure.

AltaGas' gas infrastructure touches more than 2 Bcf/d of natural gas and includes natural gas gathering and processing transmission, distribution and storage. The power infrastructure includes conventional power generation in Alberta and renewable power generation in British Columbia.

STRATEGY

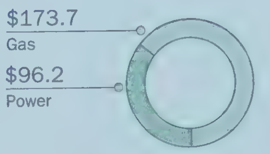
AltaGas' strategy is to increase unitholder value through the delivery of sustainable and increasing earnings and cash flow from its existing assets, as well as from the growth of its business through acquisition and construction of new gas and power infrastructure with long economic lives. Investments are diversified revenue source, fuel source, contractual term, exposure to industry cycle and location. The Trust expects growth in its business to be evenly split between gas and power over the long term through investments in Canada and the northern and western United States. The Trust has a strong track record of employing its operational expertise, energy market knowledge and financial discipline and strength to deliver sustainable

$456.6 million
Net Revenue



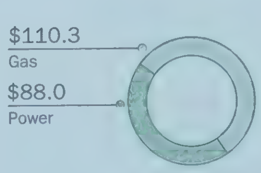
Before intersegment eliminations

$248.4 million
EBITDA



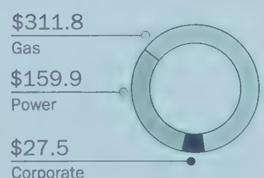
Excluding Corporate Segment

$171.2 million
Operating Income



Excluding Corporate Segment

$499.2 million
Invested Capital



returns to its investors. The Trust positions its services along the energy value chain, linking energy production to energy users. The sound long-term supply and demand fundamentals for gas and power form the foundation for AltaGas' strategy.

As part of its growth strategy, AltaGas plans to acquire and construct both gas and power infrastructure assets. In executing this growth strategy for new construction projects, AltaGas employs project management processes and disciplines. Engineering design is performed by outside engineering firms selected on the basis of best fit for a given project. For large projects, construction management is also provided by outside experts with specific experience in the execution of similar projects. AltaGas project management processes coordinate the contracting and deployment of internal and external expertise to manage execution risk.

AltaGas identifies, evaluates and pursues growth opportunities that offer strong financial returns and earnings and cash flow accretion, as well as providing the appropriate balance between risk and return. AltaGas remains open to opportunities and may deploy capital in gas and power infrastructure not currently represented within its portfolio.

AltaGas differentiates itself from its peers and competitors by linking its operating experience, gas and power market knowledge and business and financial expertise and by capitalizing on the natural hedges within its business and its strong risk management expertise.

[illegible] HIGHLIGHTS

- Connected the 102-MW Bear Mountain Wind Park to the B.C. power grid and met the conditions of Commercial Operation Date (COD) in order to receive the firm price under the 25-year energy purchase agreement (EPA) with BC Hydro. Owned and operated by AltaGas, the $200 million project was completed ahead of schedule and on budget and is B.C.'s first fully operational wind park;
- Acquired all the outstanding common shares of Utility Group not previously held by AltaGas for $204.5 million including assumed debt;
- Acquired the 75.1 percent it did not already own of the outstanding shareholder loans and common shares of Heritage Gas Limited (Heritage Gas) for $111.0 million;
- Completed the Sarnia Storage project on June 25, 2009; it was constructed on schedule and under budget;
- Completed two issues of senior unsecured medium-term notes. The $200 million April issue carries a coupon rate of 7.42 percent and matures on April 29, 2014. The $100 million June issue carries a coupon rate of 6.94 percent and matures on June 29, 2016;
- Entered into a Memorandum of Understanding (MOU) with NOVA Chemicals related to liquids extracted at the Trust's Harmattan Complex, as part of the Harmattan Co-stream Project. The MOU provides that the definitive agreements between AltaGas and NOVA Chemicals would be for an initial term of 20 years. AltaGas submitted its application for the project to the Alberta Energy Resources Conservation Board (ERCB) in April;
- Received an upgrade from both credit rating agencies. Dominion Bond Rating Services (DBRS) increased the Trust's credit rating from BBB(low) with a Positive trend to BBB with a Stable trend. Standard & Poor's (S&P) increased the Trust's rating from BBB- to BBB with a Stable outlook;
- Generated net income of $141.3 million ($1.80 per unit) compared to $163.6 million ($2.38 per unit) in 2008;
- Reported EBITDA[1] of $248.4 million ($3.16 per unit), down from $256.4 million ($3.73 per unit) in 2008;
- Generated cash from operations of $184.1 ($2.35 per unit) in 2009 compared to $205.2 million ($2.98 per unit) in 2008; and
- Generated funds from operations[1] of $202.3 million ($2.58 per unit) compared to $216.8 ($3.15 per unit) in 2008.

1 Includes financial measures not included under Canadian generally accepted accounting principles. Please see discussion in Non-GAAP Financial Measures.

Gas

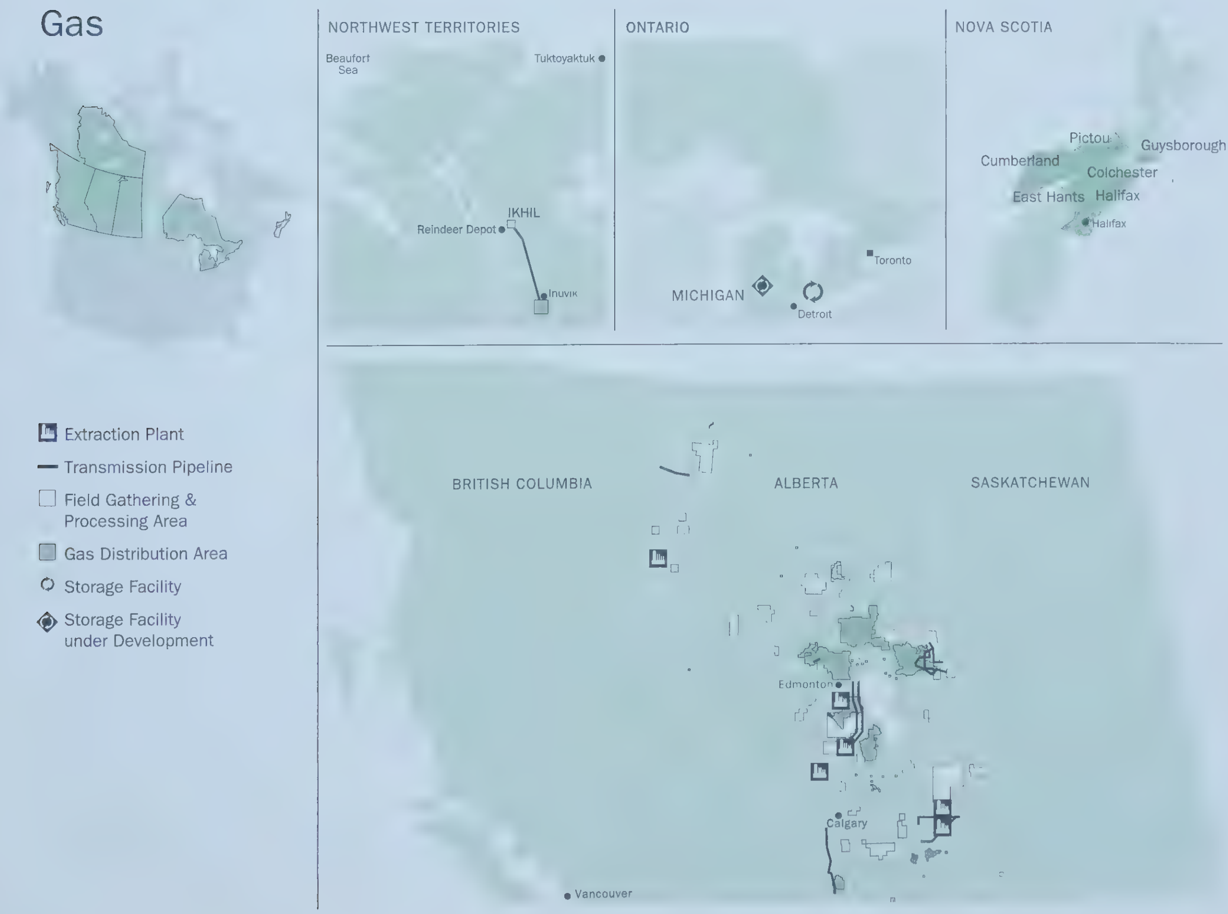
DESCRIPTION OF ASSETS

AltaGas' gas infrastructure touches more than 2 Bcf/d of natural gas and includes natural gas gathering and processing, transmission, distribution and storage. Gas gathering systems move natural gas from producing wells to processing facilities where impurities and certain hydrocarbon components are removed. The gas is then compressed to meet downstream pipelines' operating specifications for transportation. Extraction and field fractionation facilities reprocess natural gas to extract and recover ethane and natural gas liquids (NGLs). AltaGas owns 1.6 Bcf/d of extraction processing capacity and 1.2 Bcf/d of raw gas processing capacity.

Transmission pipelines deliver natural gas and NGLs to distribution systems, end users or other downstream pipelines. With the 2009 acquisition of Utility Group and Heritage Gas, AltaGas owns and operates natural gas distribution (NGD) assets that deliver natural gas to end users. These regulated assets are located in Alberta, Nova Scotia and the Northwest Territories. AltaGas uses its market knowledge and expertise to create value. It provides energy consulting and supply management services to non-residential end users, buys and resells energy, provides gas transportation and storage, and markets gas for producers.

AltaGas' Gas Segment includes:

- Interests in six NGL extraction plants with net licensed inlet capacity of 1,594 Mmcf/d. Current throughput at these facilities is 841 Mmcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin-based revenues;
- Five natural gas transmission systems with combined transportation capacity of approximately 554 Mmcf/d and three NGL pipelines with combined capacity of 151,600 Bbls/d;
- More than 70 gathering and processing facilities in 30 operating areas in western Canada and a network of 6,500 km of gathering and sales lines that gather gas upstream of processing facilities and deliver natural gas into downstream pipeline systems that feed North American natural gas markets;



- Ownership in three natural gas distribution businesses serving more than 72,000 customers, including 100 percent of both AltaGas Utilities Inc. (AUI) and Heritage Gas and 33.335 percent ownership of Inuvik Gas Ltd. (Inuvik Gas) and the Ikhil Joint Venture. The businesses were acquired in fourth quarter 2009 through the purchase of 80.2 percent of Utility Group not already owned by AltaGas and 75.1 percent of Heritage Gas not already owned by AltaGas; and
- 50 percent partnership interest in Sarnia Storage Pool Limited Partnership (Sarnia Storage), which owns 5.3 Bcf of gas storage capacity that became operational in second quarter 2009. Storage in the pool is marketed on a fee-for-service basis to credit-worthy third parties.

In addition to the segment's physical assets, AltaGas offers gas procurement, management and optimization services, which help enhance the asset base. Energy Services provides support for the infrastructure-based businesses by contracting supply and shrinkage gas for the extraction facilities, contracting and reselling capacity on the transmission pipelines and providing gas control services to balance gas flows. Energy Services also markets gas for Field Gathering and Processing (FG&P) customers, earning margins, managing credit exposure and providing additional value-added services to AltaGas' customers. In addition, it contracts and manages gas for AltaGas' gas-fired power-peaking plants. AltaGas also provides energy procurement services for large industrial and utility gas users and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

pitalizing on Opportunities

AltaGas pursues opportunities in this segment to enhance long-term unitholder value. The Trust's objectives are to:

- Increase throughput and utilization of existing facilities;
- Manage costs and improve reliability and efficiencies;
- Increase returns and mitigate volume risk by directly recovering operating costs from customers;
- Acquire and develop new gas infrastructure assets to meet customer demand;
- Enter into commercial arrangements that have long-term fixed-fee or cost-of-service components; and
- Enhance operational efficiencies and returns through consolidation of facilities, plant upgrades and integration with other business segments.

The Trust's Gas Segment provides safe and reliable gathering, processing, extraction, transportation, storage and distribution services to its customers. The strategic focus is on increasing profitability of the existing infrastructure, increasing market share and redeploying assets to capitalize on increased exploration and drilling activities in the Western Canada Sedimentary Basin (WCSB). AltaGas also focuses on increasing long-term, fixed-fee and cost-of-service contracts.

While the WCSB is considered to be a maturing basin, AltaGas remains confident that the long-term demand for natural gas, combined with improvements in exploration, drilling and completion technology, will support the long-term viability of the basin and a return to stronger gas prices. The emergence of unconventional gas plays in the WCSB, such as Montney and Horn River, as well as increased focus on horizontal multi-frac technology are expected to provide renewed life to the basin.

Growth opportunities in the Trust's Gas Segment are expected to arise from plant modifications to increase product recoveries or throughput at facilities and by increasing interests in existing plants, acquiring facilities and constructing new facilities in emerging markets or with growing demand.

The natural gas supply to all extraction plants depends on natural gas demand pull from residential, commercial and industrial usages inside and outside of Western Canada and gas liquids demand pull from the Alberta petrochemical, propane heating and Canadian oil and gas industries. AltaGas' Empress extraction plants rely on Alberta supply of natural gas for natural gas export to the NOVA Gas Transmission Ltd. (NGTL) eastern gate, while the Younger extraction plant is supplied from the robust natural gas producing region of northeast British Columbia. The Harmattan Complex is a significant service provider with a large capture area in west central Alberta. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and optimize asset utilization and increase profitability. The Harmattan Co-Stream Project is also expected to increase processing capability at the plant. Overall, the diverse nature of its extraction infrastructure should provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability.

Due to the integrated nature of AltaGas' businesses, transmission services are often offered in combination with gathering and processing, natural gas marketing and extraction services. AltaGas works with customers to create transmission solutions in areas where pipeline capacity is required to meet producer and market demands.

AltaGas expects to see increased opportunities to acquire or build gathering and processing infrastructure from or on behalf of producers wishing to redeploy capital to exploration and production activities rather than dedicating to non-core activities such as processing. AltaGas also expects there to be opportunities to increase volumes by tying in new wells and building or purchasing adjoining facilities and systems to create larger franchise areas to capture operating synergies. Based on its existing infrastructure, the Trust expects to capitalize on growing natural gas production in northeast B.C. and northwest Alberta, as well as unconventional sources of gas, such as shale and coal bed methane. In addition, most of the gas compression and processing units are skid-mounted. AltaGas is able to relocate units quickly and cost-effectively to respond to the changing processing needs of its customers.

The acquisition of NGD assets in 2009 is an example of AltaGas' strategy at work. The low-risk, long-life energy infrastructure is underpinned by regulated returns and cost-of-service recovery that provide stable and predictable cash flows. The addition of Utility Group's investments, people and growth opportunities expands, diversifies and strengthens the Gas Segment. AltaGas plans to grow its existing NGD business through infill and expansion of services within current franchise areas and by developing systems in new market areas. Heritage Gas offers strong growth potential in its franchise areas, such as the 2010 planned expansion to Bedford within the Halifax Regional Municipality and through ongoing conversion of customers with existing access to natural gas. In addition, AltaGas is actively pursuing the prudent acquisition of other utility-type infrastructure and related businesses.

The Energy Services business provides gas control and gas supply contracting services to the Gas and Power segments, as well as gas storage. AltaGas pursues additional opportunities to enhance the value of its infrastructure through services ancillary to its infrastructure-based businesses. These include increasing margins earned in transmission, maintaining the cost-effective flow of gas through extraction plants and increasing services provided to producers. Energy Services also shares gas and electricity market knowledge across all AltaGas businesses and enhances the energy value chain to more effectively serve customers across Canada.

Gas Outlook

In 2010 the Gas Segment is expected to deliver stronger results compared to 2009. This increase is largely due to the addition of NGD assets in fourth quarter 2009. AltaGas expects to invest more than $56 million into property, plant and equipment to grow its average mid-year rate base by roughly $47 million or more than 18 percent in 2010. AltaGas also expects stronger results due to higher producer activity in the FG&P business along with expansions at AltaGas' existing Pouce Coupe, Ante Creek and Acme gas processing plants, a full year of Sarnia Storage and the expiration of a gas marketing contract. These increases will be partially offset by non-recurring items that provided uplift in 2009, such as the reduction of liabilities related to natural gas transactions and the decrease of Suffield revenue deferral.

In 2010, the Trust expects to invest $5.0 million in its Acme processing facility to increase capacity by 8 Mmcf/d. In addition, the Trust expects to invest approximately $11.0 million to increase capacity by 8 Mmcf/d at the Ante Creek facility. The Pouce Coupe expansion is expected to be completed in 2010, cost approximately $24.5 million and increase capacity at the facility by 18 Mmcf/d. All three projects are expected to be completed and contributing to operating income by third quarter 2010.

Based on management's analysis of historical NGL prices along with NGL published commodity prices and the current forward curve for 2010, management expects NGL frac spread prices averaging approximately $22/Bbl.

In 2010, the Trust estimates that 13 percent of extraction volumes will be exposed to frac spread. Approximately 50 percent of the exposure has been hedged at an average price of $21/Bbl.

Gas Segment Risk Management

AltaGas' gas infrastructure assets process and transport natural gas and NGLs produced in the WCSB. Utilization of these facilities is dependent on a number of factors, including natural gas supply and demand, the ability of natural gas producers to deliver natural gas to the various pipeline systems and processing facilities, the long-term price of natural gas, the level of demand for ethane and NGLs and the regulatory environment for market participants. The extraction business is influenced by natural gas composition and the difference between the value of the ethane, propane, butane and pentanes-plus as separate marketable commodities versus their value in a heat content basis within the natural gas stream.

In the energy management business, AltaGas competes with other consulting firms. In the gas services business, AltaGas' competitors range from single-person operations to large marketing and aggregation companies. The most significant risk in the Energy Services business is counterparty credit risk. The credit-intensive nature of this business requires balance sheet support to enable the execution of fixed-price natural gas purchase and sale agreements.

AltaGas manages its exposure to financial risk in the Gas Segment using the strategies outlined in the following table:

Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Long-term volume declines	
• Contract provisions underpin capital commitments. • Long-term contracts independent of throughput, such as take-or-pay, area of mutual interest, geographic franchise with economic out.	• In 2009, 30 percent of extraction ethane production sold under long-term cost-of-service contracts. • 99 percent of net revenue from transmission contracts are cost-of-service, take-or-pay or fixed fee. • New field gathering and processing facilities and expansions underpinned by take-or-pay contracts.
• Increase market share by expanding existing facilities or acquiring or constructing new facilities.	• Completed expansion of NGL fractionation facilities at Harmattan to increase capacity for processing of trucked-in NGL mix from additional locations. • Signed contract to expand Pouce Coupe and Ante Creek facilities to serve growing production in northeast B.C. and northwest Alberta. Currently these projects are under construction. • Completed the construction and first year of operation for the Sarnia Airport Storage Pool.
• Increase geographical and customer diversity to reduce exposure to individual customer or area of the WCSB. • Strategically locate facilities to provide secure access to gas supply.	• Approximately 260 customers, with no customer representing more than 7 percent of FG&P net revenue during 2009. • Top 10 FG&P customers represented 8 percent of consolidated net revenues in 2009. • 76 FG&P facilities in 30 operating areas in three provinces within the WCSB. • Interest in six of Canada's 10 NGL extraction facilities. • Sarnia Storage in Ontario provides opportunity to capitalize on eastern gas markets.
• Collaborate with other AltaGas businesses to increase volumes through the extraction facilities.	• Empress extraction facilities maintained high-capacity utilization through gas contracted by gas services business.
Increasing operating costs	
• Acquire large working interests to control and optimize operations and maximize efficiencies. • Contractual provisions provide for recovery of operating costs.	• 40 percent of FG&P's operating costs were recovered directly from customers in 2009 and 45 percent of Extraction and Transmission (E&T) operating costs were recovered through contract provisions in 2009. • Operate 73 of 76 FG&P facilities. • Operate all transmission assets. • Operate four of six extraction facilities. • Average FG&P working interest of 93 percent and average E&T working interest of 82 percent. • Maintenance management and field purchasing programs ensure tight cost controls and equipment reliability.
Commodity price fluctuation	
• Contracting terms, processing and transportation fees independent of commodity prices through fee-for-service, take-or-pay, fixed-fee or cost-of-service provisions. • Employ hedging practices to reduce exposure to frac spread volatility and lock in margins when the opportunity arises to increase profitability and reduce earnings volatility. • Commodity Risk Policy prohibits transactions for speculative purposes. • Have strong systems and processes for monitoring and reporting compliance with Commodity Risk Policy. • In-depth knowledge of transportation systems, natural gas and NGL markets.	• Less than 14 percent of total extraction production was exposed to frac spreads in 2009. • Most ethane production sold under long term, cost-of-service or fee-for-service. • 60 percent of NGL production under long-term, fixed-fee arrangements. • The transmission business is not directly affected by commodity price fluctuations. • Hedged 74 percent of volumes exposed to frac spread for 2009 and 47 percent for 2010. • NGL is reinjected or extraction operations are reduced or suspended when uneconomical to produce. • Majority of FG&P contracts are volumetric service-fee structures, based on a rate per Mcf of throughput reducing direct commodity price risk compared to a percentage of price arrangement. • All gas service transactions are back to back with locked-in margins. • In majority of energy management business, AltaGas acts as agent, taking no direct commodity price risk.

Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Counterparty risk	
• Strong credit policies. • Continual review of counterparty credit. • Establish credit thresholds using conservative credit metrics. • Closely monitor exposures and impact of price shocks on liquidity. • Build a diverse customer and supplier base. • Base business model in energy management on agency arrangements whereby counterparty credit risk for commodity is between the supplier and end user. • Active accounts receivable monitoring and collections processes in place. • Credit mitigates included in gas processing contracts.	• Over 260 FG&P customers, with no customer representing more than 7 percent of FG&P net revenue during 2009. • Majority of the exposures are to investment-grade counterparties. • In energy management business, customers are aggregated into groups with joint and several liability for payment of fees. • No Energy Services customer represented more than 8 percent of consolidated revenues during 2009. • In 2009 AltaGas added customers in key sectors nationwide. • AltaGas purchases natural gas from a wide array of investment-grade suppliers. • No additional allowance for doubtful accounts was required in 2009 for gas processing customers. • Liens placed on natural gas volumes owned by customers, but processed by AltaGas to collect accounts receivable in accordance with contractual terms, if necessary.
Construction risk	
• Appropriate internal management structure and processes. • Major Projects group manages and monitors significant construction projects. • Strong project control and management framework. • Engage specialists in designing and building major projects. • Contractual arrangements to recover cost overruns.	• Practised effective procurement policies and procedures and vendor selection, resulting in few overruns in 2009. • Fixed-price quotes for most major equipment components. • Redeploying equipment from underutilized plant. • Sarnia Storage completed on time and under budget.
Community support	
• Maintain active corporate and regulatory affairs department.	• Held several events to inform and educate the communities in which AltaGas is constructing and developing projects.
Regulatory risk	
• Regulatory and commercial personnel monitor and react to regulatory issues. • Proactive government relations group.	• AltaGas continued active participation in industry committees and regulatory forums in 2009.
Environment and safety risk	
• Strong safety and environmental management systems, which AltaGas continually strives to improve.	• Audits resulted in AltaGas maintaining its Certification of Recognition from Alberta Human Resources and Employment. • Performed annual third-party safety and environmental audits to ensure continued compliance and improvement. • Participated in industry programs, including the annual Safety Stand Down.
Rate-regulated environment	
• Skilled regulatory department retained. • Strong relationship with regulators maintained. • Use of expert consultants when needed.	• Alberta Utilities Commission (AUC) increased AUI's return on equity to 9 percent and its equity thickness by 200 basis points. • Nova Scotia Utility and Review Board (NSUARB) granted Heritage Gas' requested rate increases.

Power

DESCRIPTION OF ASSETS

The Power Segment includes conventional power generation in Alberta and renewable power generation in British Columbia.

Conventional Power

The conventional power business comprises 392 MW of total power generation capacity in Alberta. AltaGas owns 50 percent of the Sundance B power purchase arrangements (PPAs), giving it the rights to power output and ancillary services from 353 MW of coal-fired base-load generation until December 31, 2020. PPAs were established in 1999 under Alberta's program of power industry deregulation in order to separate ownership of the physical power generation assets from marketing of output.

In addition, AltaGas has 39 MW of gas-fired power-peaking capacity in southern Alberta. This 39 MW of gas-fired peaking capacity provides fuel diversity to AltaGas' conventional power business and partial backstopping to outages at Sundance. Due to their quick ramp-up capability, the peaking plants also provide revenue from the sale of energy and ancillary services.

Renewable Power

AltaGas' renewable power generation includes the 102-MW Bear Mountain Wind Park near Dawson Creek, British Columbia, and a 25 percent interest in a 7-MW run-of-river hydroelectric generation facility.

Bear Mountain Wind Park achieved commercial operations in October 2009. The wind park is backstopped by a 25-year electricity purchase agreement with BC Hydro. AltaGas retained the green attributes and renewable energy credits related to the project. In addition, Bear Mountain has qualified for the Federal Government of Canada's ecoEnergy renewable initiative (eRPI), which grants $10/MWh generated by the Bear Mountain Wind Park for 10 years beginning on October 31, 2009. AltaGas has entered into a long-term service agreement with Enercon GmbH to operate and maintain the wind turbines.

Capitalizing on Opportunities

AltaGas pursues opportunities in this segment to enhance long-term unitholder value. The Trust's objectives are to:

- Execute power hedge strategies as appropriate to increase earnings stability and growth from the Sundance B PPAs;
- Dispatch the gas-fired peaking capacity in real time to maximize revenue from both energy sales and ancillary services;
- Identify and execute opportunities to create value from the regulation of greenhouse gas emissions;
- Capitalize on internal synergies and integration efforts with other operating lines;
- Acquire and develop power infrastructure backstopped by long-term power sales arrangements or supported by strong power supply and demand fundamentals;
- Diversify power generation portfolio by geography and fuel source;
- Develop operating capability in other energy sources; and
- Capitalize on increasing demand for clean power by investing in renewable power projects across Canada and the northern and western U.S.

AltaGas' strategy is to expand its power infrastructure to ensure the long-term sustainability of this business and offset the expiration of the Sundance B PPAs on December 31, 2020. Growth is focused on clean and renewable sources of energy.

The demand for renewable and clean generating capacity continues to be strong across North America, as industry prepares to address climate change legislation and utilities are faced with renewable portfolio standards. The poor economic environment has resulted in reduced demand for power, and in Alberta specifically, average power demand has remained essentially unchanged since 2008, notwithstanding the fact that new peak demand records were set in December 2009. AltaGas expects power demand growth to follow suit with a broader economic recovery, which will subsequently lead to a recovery in power prices. Based on broker reports published February 11, 2010, forward prices in Alberta are unsustainably low, in the high $40s/MWh. AltaGas expects that any significant new generation project that is not already committed to will be deferred until forward prices recover. The Sundance B facility is among the lowest-cost producers of power in the province, uniquely positioning AltaGas to maintain profitable operations during difficult economic conditions. The power generated by the Bear Mountain Wind Park is sold to BC Hydro at a fixed price with 50 percent CPI escalators for 25 years and is therefore not exposed to fluctuations in the market value of power.

Opportunities to develop and own additional power generation are likely to arise due to the growing North American demand for cleaner energy sources, such as natural gas, hydroelectric and wind. The planned decommissioning of thermal plants in Ontario and, beginning in 2010, Alberta may prompt additional growth opportunities to develop new clean power generation

capacity. The 102-MW Bear Mountain Wind Park, which commenced commercial operations October 24, 2009, is an example of a clean energy project and of AltaGas' strategy in action.

AltaGas has approximately 1,900 MW of renewable power under development, including 1,500 MW of wind power developments and 400 MW of run-of-river hydroelectric developments. The wind projects are geographically dispersed in western North America, with 500 MW in Canada and 1,000 MW in the northern and western United States, while the run-of-river projects are focused in British Columbia.

Power Outlook

In 2010 almost two-thirds of the power delivered to the Alberta Power Pool from the Sundance Plant is hedged at a price of $72, slightly lower than the average hedge price in 2009. Current forward prices, as published in daily broker reports, are in the high $40's/MWh for the balance of 2010. This reflects a temporary oversupply situation in the Alberta Power market that management does not believe is sustainable over the long term. According to the Alberta Electric System Operator (AESO), if the demand for power and the rate of growth in Alberta continues as forecast, the addition of up to 3,800 MW of new generation may be required by 2016. A large coal unit in Alberta is expected to be retired during 2010, resulting in a reduction of supply that will not be fully replaced in the near term, and improved economic conditions are expected to bring increased power demand to the province. Offsetting weakness in the spot market will be the impact of a full-year contribution from Bear Mountain Wind Park, as well as the anticipated addition of the Harmattan Co-generation facility, currently expected to be on-line in the fourth quarter of 2010.

AltaGas is constructing a 13-MW gas-fired co-generation facility at its Harmattan Complex, which is expected to cost approximately $22 million. The co-generation facility will deliver power to the Alberta electrical grid and use steam to provide process heat to the Harmattan Complex. This is a highly efficient process of generating power and will reduce greenhouse gas emissions. It also adds further diversity to AltaGas' portfolio of generation assets and will provide another source of capacity to backstop the Sundance B PPAs. The facility is expected to be commissioned in fourth quarter 2010.

Risk Manageme

The main risks faced in the Power Segment are power prices, the cost of power, the volume of power generated, counterparty risk and regulatory risks related to the deregulation of power, market regulation and environmental legislation. Power results are generally driven by volumes of power generated, hedge prices, spot power prices and the cost of power and transmission.

Power

Power prices are impacted by fluctuations in supply and demand as a consequence of weather, customer usage, economic activity and economic growth. The cost of power is driven by operating costs, changes in transmission rates and power available for sale, mainly due to outage and force majeure events. AltaGas mitigates these risks through the strategies outlined in the following table:

Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
[illegible]	
• Disciplined hedging strategy with hedge targets approved by the Board of Directors. • Monitor hedge transactions through Risk Management Committee. • In-depth Alberta power market knowledge and experience. • Hedge own electrical demand requirements. • Own and operate gas-fired peaking capacity to backstop PPAs and sell energy and ancillary services.	• Financial hedge contracts generally have terms ranging from one month to three years. • Average sales price received in 2009 was $69.37/MWh, compared to average monthly Alberta Power Pool price range of $31.53/MWh to $92.97/MWh. • Supplied approximately 14 MW for own use in 2009. • Supplied approximately 60 MW to Alberta power retail customers under one- to five-year contracts. • Peaking plants contributed $4.1 million to net revenue in 2009 through sales of ancillary services and energy.
[illegible]	
• PPAs include specified target availability levels. • Diversification of fuel sources and geography. • Hedging strategy to balance price and operating risk. • Reciprocal backstopping agreements with another generator to supply power at a fixed price during force majeure events.	• The operator of the Sundance B plant is obligated to provide AltaGas financial compensation for shortfalls below the specified target availability level, which was 86 percent of rated capacity in 2009. Payment is based on the difference between actual and target availability multiplied by the 30-day rolling average power price (RAPP). • 39 MW of gas-fired generation provided partial operational backstopping to the Sundance PPAs. • Wind and hydro power projects under development. • Bear Mountain Wind Park in commercial service. • Power delivered from a total of 67 independent generation sources.
[illegible]	
• Hedge power costs. • Avoid commodity price exposure on electricity energy sources.	• Cost of power from the coal-fired generation based on PPA indices not market price of coal. • Modest decrease in cost of power from Sundance PPAs in 2009.
[illegible]	
• Strong credit policies. • Continual review of counterparty credit. • Establish credit thresholds using conservative credit metrics. • Closely monitor exposures and impact of price shocks on liquidity.	• All relevant policies and processes were maintained in 2009. • All financial hedge counterparties are investment-grade. • No counterparty defaults in 2009. • Alberta retail credit risk has little impact on hedge portfolio on an individual basis. In the event of a default, AltaGas can sell the power on the spot market.
[illegible]	
• Major Projects group manages and monitors significant construction projects. • Strong project control and management framework.	• Completed Bear Mountain Wind Park ahead of schedule and on budget.
Community [illegible]	
• Active corporate and regulatory affairs departments.	• Held several events to inform and educate the communities in which AltaGas is constructing and developing projects.
[illegible]	
• Appropriate human resources deployed on regulatory issues. • Build risk mitigation into contracts where possible.	• AltaGas' Sundance B PPAs have provisions for financial relief in the event that policies and regulations render PPAs uneconomic. • AltaGas personnel participate in industry policy and oversight committees.

Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Environmental and safety risk	
• Strong safety and environmental management systems, which AltaGas continually strives to improve. • Focus on mitigating the impact of the Alberta Specified Gas Emitters Regulation (SGER).	• Bear Mountain Wind Park generates emission credits. • Bantry and Parkland gas-fired peaking plants compress natural gas to drive the peaking plant starter motors. The compressed gas is then captured and cycled through the peaking plants rather than vented into the environment. • Potentially generate offsets and emissions performance credits from existing AltaGas operating facilities. • Possible offset of Alberta SGER costs through higher Alberta Power Pool prices.

CONSOLIDATED RESULTS

Years ended December 31

($ millions)	2009	2008	2007
Revenue	1,268.3	1,816.8	1,428.4
Unrealized gain (loss) on risk management	3.7	11.0	1.1
Net revenue [1]	456.6	476.5	324.0
EBITDA [1]	248.4	256.4	173.7
EBITDA before unrealized gain (loss) on risk management [1]	244.7	245.4	172.6
Operating income [1]	174.2	188.0	126.6
Net income	141.3	163.6	108.8
Net income before tax-adjusted unrealized gain (loss) on risk management [1]	139.7	158.0	109.3
Total assets	2,629.1	2,132.3	1,172.7
Total long-term liabilities	719.1	851.6	313.5
Net additions of capital assets	486.5	808.0	21.8
Distributions declared [2,3]	170.2	147.1	118.6
Cash flows			
Cash from operations	184.1	205.2	183.3
Funds from operations [1]	202.3	216.8	162.9

($ per unit except as noted)	2009	2008	2007
EBITDA [1]	3.16	3.73	3.03
EBITDA before unrealized gain (loss) on risk management [1]	3.12	3.57	3.01
Net income	1.80	2.38	1.90
Net income per diluted unit	1.79	2.36	1.89
Net income before tax-adjusted unrealized gain (loss) on risk management [1]	1.78	2.30	1.90
Distributions declared [2,3]	2.160	2.125	2.065
Cash flows			
Cash from operations	2.34	2.98	3.19
Funds from operations [1]	2.58	3.15	2.84
Units outstanding (millions)			
Weighted average number of units outstanding for the year (basic)	78.5	68.8	57.4
Weighted average number of units outstanding for the year (diluted)	79.4	69.7	57.4
End of year	80.3	71.9	58.1

1 Non-GAAP financial measure. See discussion in the Non-GAAP Financial Measures section of this MD&A.

2 Distributions declared of $0.180 per unit per month commencing August 2008, $0.175 per unit per month from August 2007 to July 2008. From August 2006 to July 2007, distributions of $0.170 per unit per month were declared. From March 2006 to July 2006, distributions of $0.165 per unit per month were declared. From August 2005 to February 2006, distributions of $0.160 per unit per month were declared.

3 Excludes special distribution of AltaGas Utility Group Inc. shares in September 2007, providing an additional non-cash distribution of $0.076 per unit.

Net income for 2009 was $141.3 million compared to $163.6 million in the same period in 2008, which included a one-time tax recovery of $13.8 million. Excluding this recovery, net income for 2008 was $149.8 million or $8.5 million higher than the current period. Net income was $1.80 per basic unit for 2009 compared to $2.38 per basic unit for 2008.

During 2009, the Gas Segment performed well due to a reduction of liabilities related to natural gas transactions, higher extraction volumes, the addition of NGD assets in fourth quarter 2009, no major extraction turnarounds and a one-time adjustment to transmission revenues previously deferred. These increases were partially offset by lower processing volumes at FG&P facilities as producers reduced drilling activities and shut-in production in response to weak gas prices and lower realized frac spreads. The Power Segment reported lower results primarily due to declines in realized power prices but benefited from lower transmission and environmental costs as well as contributions from Bear Mountain Wind Park, which commenced commercial operations in fourth quarter 2009. The Corporate Segment benefited from higher investment income offset by lower unrealized gains on risk management contracts compared to 2008. The Trust reported higher interest expense in 2009 compared to 2008 due to higher average debt balances and a higher average borrowing rate. Income tax expense was higher in 2009 due to a one-time tax recovery of $13.8 million in 2008, partially offset by the tax impact for financial instruments and lower income subject to tax.

On a consolidated basis, net revenue for 2009 was $456.6 million compared to $476.5 million in 2008. In the Gas Segment, net revenue increased due to the addition of the NGD assets in fourth quarter 2009, higher extraction volumes, adjustments to liabilities, previously deferred transmission revenues, contribution from Sarnia Storage and expanded transmission business. These increases were partially offset by lower throughput in most FG&P areas, lower frac spreads and lower operating cost recoveries. In the Power Segment, net revenue decreased due to lower spot power prices in Alberta, the gain on assets sold in 2008 and lower contribution from gas-fired peaking plants, partially offset by strong hedge prices and lower PPA and transmission costs. The Corporate Segment reported higher net revenue due to investment income, partially offset by lower unrealized gains on risk management contracts.

Operating and administrative expense for 2009 was $208.2 million, down from $221.5 million in 2008. The decrease was largely due to fewer turnarounds compared to prior year, when approximately $7.4 million of turnaround costs were recorded. The decrease is further explained by a $2.6 million charge for project development costs in 2008. Cost control measures have also resulted in a decline in administrative costs. These decreases were partially offset by incremental costs associated with the growth of the Trust, including the addition of NGD assets.

Amortization expense for 2009 was $74.1 million compared to $67.0 million last year. The increase was due to the growth in AltaGas' asset base from acquisitions and construction activities.

Interest expense in 2009 was $31.8 million compared to $27.4 million in 2008. The increase was due to higher average debt balances of $691.5 million compared to $581.0 million in 2008. The average borrowing rate was 5.6 percent in 2009 compared to 5.3 percent in 2008.

Income tax expense in 2009 was $1.2 million compared to a recovery of $1.6 million in 2008. The increase was largely due to a one-time $13.8 million recovery of future income taxes in third quarter 2008 as a result of legal entity ownership changes within the Trust structure, partially offset by the tax impact for financial instruments and lower income subject to tax.

Financial results for 2008 reflect the strong operating performance of AltaGas' energy infrastructure assets. In 2008 the Trust increased its assets by approximately $600 million as a result of the Taylor acquisition. The Trust also completed approximately $50 million of growth and enhancement initiatives in late 2008 at the Harmattan Complex. Net income increased by 50 percent year-over-year. The Gas and Power Segments each reported year-over-year operating income increases of 75 percent and 25 percent, respectively. The Gas Segment reported strong results despite turnarounds at four extraction facilities in 2008, which resulted in lost revenues of $3.7 million, operating costs of $4.3 million and a major turnaround at one field processing facility, which resulted in $1.0 million in lower operating income. The Power Segment reported strong results due to higher power prices realized on both spot and hedged sales as well as higher contributions from the gas-fired peaking plants. The Trust recorded higher interest costs mainly due to the increased debt balances as a result of the Taylor acquisition and lower taxes primarily as a result of changes within the Trust's legal structure.

Net income in 2008 was $163.6 million ($2.38 per unit – basic) compared to $108.8 million ($1.90 per unit – basic) in 2007. Excluding a $13.8 million reduction in future tax liability related to changes in the Trust structure and a $5.6 million after-tax gain on risk management contracts, net income was $144.2 million ($2.10 per unit – basic). Excluding the Specified Investment Flow-Through (SIFT) tax of $5.4 million and a $6.1 million non-cash tax benefit due to the reduced federal tax rates recorded in 2007, net income in 2007 was $108.1 million ($1.88 per unit – basic).

Operating income across all segments increased by 50 percent to $188.0 million in 2008 compared to $126.6 million in 2007.

Operating income from the Gas Segment was $103.6 million in 2008 compared to $59.3 million in 2007. In the Power Segment, operating income was $117.9 million in 2008 compared to $94.6 million in 2007. In 2008 operating income from the Gas and Power Segments was 47 percent and 53 percent, respectively, of total business operating income compared to 39 percent and 61 percent, respectively, for 2007. The improved balance between the Gas and Power Segments reflects the impact of the Trust's strategy to have a more balanced portfolio of assets.

In the Gas Segment, operating income increased mainly due to the larger energy infrastructure asset base as a result of the Taylor acquisition, higher rates and other revenues in FG&P and higher frac spreads, partially offset by lower throughput due to declines, planned and unplanned downtime in certain FG&P areas and lower volumes processed at the extraction plants owned prior to January 2008. The Gas Segment reported strong results despite approximately $10 million impact of five extraction plant turnarounds, planned and unplanned downtime at some field processing facilities and a fire at the Harmattan Complex.

In the Power Segment, operating income increased due to higher average power prices, higher contributions from the peaking plants, a deferral account settlement from the AESO and a gain on the sale of one of the Trust's power development projects, partially offset by a more favourable RAPP in 2007, higher transmission costs and higher environmental compliance costs.

The operating loss in the Corporate Segment increased primarily due to higher costs to support the growth of the Trust, general cost escalations and lower investment income, partially offset by the unrealized gain reported on risk management contracts.

Consolidated net revenue for 2008 was $476.5 million compared to $324.0 million in 2007. In the Gas Segment, net revenue increased due to the addition of extraction, processing and transmission facilities, higher operating cost recoveries, higher rates and other revenues in FG&P and higher frac spreads. These increases were partially offset by lower throughput in certain FG&P areas, the sale of non-core assets in mid-2007, lower fixed-price gas and transport sales and lower volumes processed at the extraction plants owned prior to the acquisition of the Taylor extraction facilities. In the Power Segment, net revenue increased due to higher average price realized on the sale of power, higher contributions from the peaking plants, a deferral account settlement from the AESO and the gain on sale of a power development project, partially offset by a higher RAPP in 2007, higher transmission and environmental compliance costs.

Operating and administrative expense for 2008 was $221.5 million compared to $150.3 million in 2007. The increase was due to costs related to new facilities, turnaround costs and higher compensation and administrative costs.

Operating costs included approximately $8.0 million related to turnaround costs incurred during the year. Approximately 36 percent was recovered. Administrative costs included approximately $2.0 million in non-recurring technology costs.

Amortization expense for 2008 was $67.0 million compared to $47.1 million in 2007. The increase was primarily due to new and expanded facilities in the Gas Segment, partially offset by the disposition of non-core assets in the second quarter of 2007. Administrative costs include approximately $2.0 million in non-recurring technology costs.

Interest expense in 2008 was $27.4 million compared to $11.9 million in 2007. The increase was primarily due to higher average debt balances of $581.0 million in 2008 compared to $234.9 million in 2007. The average borrowing rate for 2008 was 5.3 percent, which was consistent with 2007.

Income tax recovery for 2008 was $1.6 million compared to income tax expense of $5.9 million in 2007. Income tax expense was lower as a result of certain tax planning initiatives undertaken by management in 2008. The income tax expense was lower by $11.8 million as a result of applying a lower tax rate to the future income tax liability that arose from changes in the legal entity structure of the Trust. This internal reorganization had the added benefit of reducing income tax expense by $13.3 million through use of higher intercompany interest offset by income taxes of $12.0 million due to higher operating income. The lower 2008 income tax expense was partially offset by $2.3 million in current taxes from the sale of a power project, $1.7 million due to higher mark-to-market gains on risk management contracts and $1.5 million due to an adjustment for the estimated tax asset basis of the Trust. For comparative purposes, the enactment of the SIFT tax during 2007 increased income tax expense by $5.3 million. Later in the same year, income tax expense was reduced by $5.4 million due to the federal income tax rate reductions.

BAL CAPITAL MARKET CONDITIONS

Although uncertainty in global financial markets persisted in 2009, AltaGas' financial position and ability to generate cash from its operations in the short and long terms have remained strong.

Throughout 2009, the Trust demonstrated its ability to access capital markets. In February AltaGas completed an equity offering that generated gross proceeds of approximately $100 million, and in March the Trust secured a new $250 million credit facility with a syndicate of eight banks. AltaGas also completed two issuances of medium-term notes (MTN) in second quarter 2009 for total proceeds of $300 million.

The Trust's liquidity position remains sound, underpinned by highly predictable cash flow from operations, as well as revolving bank lines of $816.0 million, of which $262.2 million was available as at December 31, 2009 and strong participation in the distribution reinvestment plan (DRIP).

Based on projects currently under review, development or construction, AltaGas expects capital expenditures for 2010 to be approximately $225 million, 70 percent for gas and 30 percent for power. To date, approximately $80 million of capital has been committed for 2010. Growth capital is funded through AltaGas' cash from operations, DRIP proceeds and credit facilities. The following projects have an expected in-service date post-2010.

mattan Co-stream Project

On April 23, 2009, AltaGas submitted its application for the Harmattan Co-stream Project to the ERCB. The project, as currently designed, is expected to cost in the range of $100 to $120 million. The project will allow 250 Mmcf/d of rich, sweet natural gas sourced from the NGTL Western Alberta System to be processed using spare capacity at the Harmattan Complex to recover ethane and NGL. AltaGas expects a favourable decision from the ERCB in the near future and expects the project to commence operations in late 2011.

On July 6, 2009, AltaGas entered into a Memorandum of Understanding (MOU) with NOVA Chemicals Corporation (NOVA Chemicals). The MOU provides that the definitive agreements between AltaGas and NOVA Chemicals would be for an initial term of 20 years, AltaGas would deliver all liquids or co-stream gas products on a full cost-of-service basis to NOVA Chemicals and would provide that all capital expenditures and operating costs related to the proposed project be fully recovered through fees under normal operations. The MOU is subject to normal conditions precedent, including execution and delivery of mutually satisfactory definitive agreements between AltaGas and NOVA Chemicals, a favourable decision on the Harmattan Co-stream application currently under review by the ERCB and approval by the boards of directors of AltaGas and NOVA Chemicals.

ton Gas Storage Project

AltaGas has made an offer to acquire Landis Energy Corporation, which is a developer of underground natural gas storage facilities. The most advanced project under development by Landis is the Alton natural gas storage project, located near Truro, Nova Scotia, which is expected to serve customers seeking to manage natural gas supply requirements in eastern Canada and the northeast United States.

Walker Ridge Project

AltaGas is developing the 70-MW Walker Ridge wind project in northern California. AltaGas has selected the turbines and a preliminary layout and has completed the preliminary engineering studies. The project is located near existing transmission lines and requires limited system upgrades to interconnect. It is located in Lake Colussa County, close to San Francisco load. This project is proceeding with the environment and land permitting process, and AltaGas is actively seeking bilateral agreements for sale of the power output.

Glenridge Project

AltaGas is developing the 100-MW Glenridge wind project in southeast Alberta. AltaGas has secured a 17,000 acre land package and has applied to the Federal Government of Canada for eRPI funding. AltaGas has completed its AESO transmission system impact study and expects to submit its AUC application and begin the facilities study in first quarter 2010. AltaGas is actively seeking a market for its prospective green credits. Once in service, the project will use these green credits to offset compliance costs associated with the Trust's Sundance B PPA.

Roughrider Project

AltaGas is developing the 90-MW Roughrider wind project in North Dakota. The project holds easements of approximately 27,000 acres on private land. AltaGas is currently in the Western Area Power Administration (WAPA) and Midwest ISO transmission queues and has determined there are limited transmission upgrades required to interconnect to the WAPA transmission system. AltaGas is seeking green credit and energy markets with local and out-of-state utilities.

AltaGas continues to advance its early-stage wind development projects by setting up meteorological towers to collect wind data, and initiating permit applications and transmission studies.

Hydroelectric

AltaGas is developing a portfolio of run-of-river hydroelectric projects in the province of British Columbia (B.C.), including three projects in northwest B.C.: Forrest Kerr, McLymont Creek and Volcano Creek (collectively, NW Projects). The NW projects have a combined generating capacity of approximately 277 MW and are currently the subject of discussions with the Government of B.C. These discussions include considerations relating to the announcement by the Government of B.C. to upgrade and extend the electricity transmission capabilities in B.C.'s northwest, specifically the Northwest Transmission Line (NTL). The NTL upgrade would extend the British Columbia Transmission Corporation's (BCTC) transmission grid to within 44 km of the NW Projects.

Log and Kookipi Creek Run-of-River Project

AltaGas is advancing engineering studies, preparing comprehensive environmental submissions and engaging with First Nations to support the development of the Log and Kookipi Creek projects. Located in southern British Columbia, these two 10-MW capacity run-of-river projects have 40-year electricity sales agreements with BC Hydro. Subject to successful conclusion of permitting and other activities, construction of these two projects is expected to begin in 2011 with an in-service in 2013.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. All of the measures have been calculated to be consistent with previous disclosures. These measures provide additional information that management believes is meaningful regarding AltaGas' operational performance, liquidity and its capacity to fund distributions, capital expenditures and other investing activities. The specific rationale for, and incremental information associated with, each non-GAAP measure is discussed below.

References to net revenue, operating income, EBITDA, EBITDA before unrealized gain (loss) on risk management, net income before tax-adjusted unrealized gain (loss) on risk management, net income before tax and funds from operations throughout this document have the meanings as set out in this section.

Net Reve

Years ended December 31 ($ millions)	2009	2008	2007
Net revenue	456.6	476.5	324.0
Add:			
Cost of sales	811.7	1,340.3	1,104.4
Revenue (GAAP financial measure)	1,268.3	1,816.8	1,428.4

Net revenue, which is revenue less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, since changes in the market price of natural gas and power affect both revenue and cost of sales.

Years ended December 31 ($ millions)	2009	2008	2007
Operating income	174.2	188.0	126.6
Add (deduct):	(31.8)	(27.4)	(11.9)
Interest			
Foreign exchange gain	–	1.4	–
Income taxes	(1.2)	1.6	(5.9)
Net income (GAAP financial measure)	141.3	163.6	108.8

Operating income is a measure of the Trust's profitability from its principal business activities prior to how these activities are financed or how the results are taxed. The measure is used by management to assess the operating performance of the business segments since it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses and amortization.

Years ended December 31 ($ millions)	2009	2008	2007
EBITDA	248.4	256.4	173.7
Add (deduct):			
Amortization and goodwill impairment	(74.1)	(67.0)	(47.1)
Interest	(31.8)	(27.4)	(11.9)
Income taxes	(1.2)	1.6	(5.9)
Net income (GAAP financial measure)	141.3	163.6	108.8

EBITDA is a measure of the Trust's operating profitability. EBITDA provides an indication of the results generated by the Trust's principal business activities prior to accounting for how these activities are financed, assets are amortized or how the results are taxed. EBITDA is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses.

Years ended December 31 ($ millions)	2009	2008	2007
EBITDA before unrealized gains on risk management	244.7	245.4	172.6
Add (deduct):			
Unrealized gains on risk management	3.7	11.0	1.1
Amortization and goodwill impairment	(74.1)	(67.0)	(47.1)
Interest	(31.8)	(27.4)	(11.9)
Income taxes	(1.2)	1.6	(5.9)
Net income (GAAP financial measure)	141.3	163.6	108.8

EBITDA before unrealized gain on risk management is a measure of the Trust's operating profitability without the impact of the change in fair value of risk management contracts. EBITDA before unrealized gain on risk management reports the results of the Trust's principal business activities on a realized basis and prior to how business activities are financed, assets are amortized or how the results are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk, and therefore evaluates company performance excluding unrealized gain from risk management activities. EBITDA before gains or losses on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue adjusted for unrealized gain (loss) on risk management less operating and administrative expenses.

Net Income Before Tax-Adjusted Unrealized Gains on Risk Management

Years ended December 31 ($ millions)	2009	2008	2007
Net income before tax-adjusted unrealized gains on risk management	139.7	158.0	109.3
Add (deduct):			
Unrealized gains on risk management	3.7	11.0	1.1
Income tax expense on risk management	(2.1)	(5.4)	(1.6)
Net income (GAAP financial measure)	141.3	163.6	108.8

Net income before tax-adjusted unrealized gain on risk management is a better reflection of actual performance than net income, since changes related to risk management are based on unrealized estimates relating to commodity prices, interest rates and foreign exchange rates over time. AltaGas enters into financial instruments to manage risk, not as a principal business activity, and therefore evaluates performance prior to accounting for the unrealized gain from risk management activities. Net income before tax-adjusted unrealized gain on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net income adjusted for unrealized gain on risk management and its related income tax expense.

Funds from Operations

Years ended December 31 ($ millions)	2009	2008	2007
Funds from operations	202.3	216.8	162.9
Add (deduct):			
Net change in non-cash working capital and asset retirement obligations settled	(18.2)	(11.6)	20.4
Cash from operations (GAAP financial measure)	184.1	205.2	183.3

Funds from operations is used to assist management and investors in analyzing financial performance without regard to changes in the Trust's non-cash working capital in the period. Funds from operations as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with GAAP. Funds from operations is calculated from the Consolidated Statements of Cash Flows and is defined as cash provided by operating activities before changes in non-cash working capital and expenditures incurred to settle asset retirement obligations.

RESULTS OF OPERATIONS BY SEGMENT

Operating Income

Year ended December 31 ($ millions)	2009	2008
Gas	110.3	103.6
Power	88.0	117.9
Corporate	(24.1)	(33.5)
	174.2	188.0

GAS

Operating Income

Year ended December 31 ($ millions)	2009	2008
E&T	88.6	83.8
FG&P	6.3	20.4
NGD	7.4	–
Energy Services	8.0	(0.6)
Total Gas operating income	110.3	103.6

Operating income from the Gas Segment was $110.3 million in 2009 compared to $103.6 million in 2008. In 2009, the Gas Segment focused on integrating both acquired and constructed assets. Operating income generated from both the new NGD assets and Sarnia Storage contributed to the increase in operating income. The Trust also focused on optimizing its existing business units to improve operating income, including a positive adjustment to transmission revenues that were previously deferred and liabilities related to natural gas transactions, higher NGL volumes, higher contracted volumes in the transmission business and higher extraction volumes processed in part due to no major turnarounds in 2009. These increases to operating income were partially offset by lower throughput in most FG&P areas due to lower producer activity and gas well shut-ins during 2009. Lower realized frac spreads received, lower fixed-price natural gas transportation sales and one turnaround in the FG&P business also contributed to lowering operating income.

Net revenue in the Gas Segment for 2009 was $340.1 million compared to $334.2 million in 2008. Net revenue increased $9.4 million from a reduction of liabilities related to natural gas transactions, $6.0 million due to higher NGL volumes, $4.5 million due to increased transmission revenues, which included a one-time adjustment of $3.3 million for revenues that were previously deferred and increased contracted volumes, $3.9 million as a result of the 2008 capital program at the Harmattan Complex and $3.8 million due to the addition of Sarnia Storage. Net revenue also increased $7.4 million due to the acquisition of NGD assets in fourth quarter 2009. These increases were partially offset by $12.7 million in lower realized frac spreads, $12.4 million in lower volumes processed at FG&P facilities, $4.3 million due to lower fixed-price natural gas transportation sales, $3.2 million from lower facility service revenues and $1.0 million due to a gas marketing contract that expired in fourth quarter 2009.

Operating and administrative expense for 2009 was $166.4 million, down from $173.2 million in 2008. The decrease was largely due to fewer turnarounds than 2008, when approximately $7.4 million of turnaround costs were recorded. The decrease is further explained by a $2.6 million charge for project development costs in 2008. Cost control measures have also resulted in a decline in administrative costs. These decreases were partially offset by incremental costs associated with the addition of new assets and businesses acquired by the Trust during the second half of 2008 and fourth quarter 2009.

Amortization expense for 2009 was $63.4 million compared to $57.3 million in 2008. The increase was due to the growth in AltaGas' asset base from acquisition and construction activities.

Extraction and Transmission (E&T) Variance Analysis

Operating income in the E&T business for 2009 was $88.6 million compared to $83.8 million in 2008. Operating income increased $6.0 million due to higher NGL volumes, $4.5 million from increased transmission revenues, of which $3.3 million was a one-time adjustment for revenues previously deferred and increased contracted transmission volumes, $3.9 million as a result of the 2008 Harmattan Complex capital program, lower operating costs of $2.9 million and $1.3 million due to the EDS upgrade and increased transmission cost-of-service fees. These increases were partially offset by $12.7 million in lower realized frac spreads, $2.7 million of higher amortization related to 2008 capital programs and $0.6 million due to lower fees-for-service revenues in the extraction business.

Field Gathering and Processing (FG&P) Variance Analysis

Operating income from the FG&P business was $6.3 million in 2009 compared to $20.4 million in 2008. Operating income decreased by $12.4 million due to lower throughput, $3.2 million due to lower facility service revenues and $1.0 million due to higher amortization. These decreases were partially offset by $2.5 million from lower operating costs and $1.0 million due to lower turnaround costs in 2009 compared to 2008.

Natural Gas Distribution Varian

Operating income for the NGD business has been included in 2009 with the acquisition of Utility Group effective October 8, 2009 and the remaining 75.1 percent of Heritage Gas effective November 18, 2009. The results of NGD assets are highly seasonal, with the majority of natural gas deliveries occurring during the winter heating season. For 2009, the NGD business contributed $7.4 million to operating income.

Energy Services Variance Anal

Operating income in the Energy Services business was $8.0 million for 2009 compared to an operating loss of $0.6 million for 2008. Operating income increased approximately $9.4 million as a result of the reduction of liabilities related to natural gas transactions, $3.2 million from Sarnia Storage and $1.0 million loss in 2008 as a result of a gas marketing contract that expired in early fourth quarter 2009. These increases were partially offset by $4.3 million in lower fixed-price natural gas and transportation sales and a one-time loss of $0.8 million for risk management contracts.

Year ended December 31	2009	2008
E&T		
Extraction inlet gas processed (Mmcf/d) [1]	841	801
Extraction ethane volumes (Bbls/d) [1]	26,817	24,795
Extraction NGL volumes (Bbls/d) [1]	13,236	12,242
Total extraction volumes (Bbls/d) [1]	40,053	37,037
Frac spread – realized ($/Bbl) [1,2]	23.46	26.97
Frac spread – average spot price ($/Bbl) [1]	19.51	28.79
Transmission volumes (Mmcf/d) [1,3]	324	379
FG&P		
Processing capacity (Mmcf/d) [4]	1,172	1,172
Processing throughput (gross Mmcf/d) [1]	453	541
Capacity utilization (%) [4]	39	46
Average working interest (%) [4]	93	92
NGD		
Natural gas deliveries – end-use (PJ) [5,6]	6.62	–
Natural gas deliveries – transportation (PJ) [5,6]	0.55	–
Service sites at year-end [7]	72,717	–
Degree day variance (%) [8]	9.9	–
Energy Services		
Energy management service contracts [9]	1,748	1,711
Average volumes transacted (GJ/d) [10]	354,513	302,392

1 Average for the period.
2 Indicative frac spread or NGL margin, expressed in dollars per barrel of NGL and derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.
3 Excludes NGL pipeline volumes.
4 As at the end of the reporting period.
5 Petajoule (PJ) is one million gigajoules (GJ).
6 Deliveries reflect Utility Group as of October 8, 2009, when the Trust obtained control, and 100% of the deliveries of Heritage Gas as of November 18, 2009.
7 Service sites reflect all of the service sites of AUI, Heritage Gas and Inuvik Gas.
8 Degree days relate to AUI's service area. A degree day is the cumulative extent to which the daily mean temperature falls below 15°C. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations.
9 Active energy management service contracts at the end of the reporting period.
10 Average for the period. Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

Average ethane and NGL volumes in the extraction business increased by 2,022 Bbls/d and 994 Bbls/d, respectively, in 2009 compared to 2008 due to the completion of projects that attracted approximately 25 Mmcf/d of incremental natural gas at the Harmattan Complex for the full year compared to two months in 2008 and higher throughput at Younger, Harmattan and Joffre due to no turnarounds in 2009. The increases were partially offset by intermittent curtailment of inlet gas at other extraction plants in response to lower frac spreads in early 2009. Natural gas volumes transported in the transmission business in 2009 decreased from 2008 due to lower volumes moved on the Suffield system. However, in the transmission business, pipeline throughput has minimal impact on the financial results due to cost-of-service and take-or-pay contractual arrangements in place.

In FG&P, throughput in 2009 averaged 453 Mmcf/d compared to 541 Mmcf/d in 2008. Approximately 65 percent (57 Mmcf/d) of the decline was due to lower producer activity not offsetting natural declines, approximately 20 percent was due to producers shutting-in natural gas production due to low commodity prices in the latter half of the year and the remainder was due to planned and unplanned downtime. Utilization reported in 2009 was 39 percent compared to 46 percent in 2008, primarily due to lower throughput at most facilities. In response to low natural gas prices, several of AltaGas' customers temporarily shut-in production at some facilities during the latter half of 2009.

Operating income in the Power Segment in 2009 was $88.0 million compared to $117.9 million in 2008. During 2009, the Power Segment was focused on the completion of Bear Mountain Wind Park, which reached commercial operation ahead of schedule and on budget. Contributions from Bear Mountain and a strong hedging program were more than offset by lower spot power prices.

Net revenue for 2009 was $102.2 million compared to $129.0 million for 2008. Net revenue decreased $26.8 million due to lower spot prices in Alberta, which averaged $47.84/MWh in 2009 compared to an average of $89.95/MWh in 2008. Net revenue was also lower due to a $1.6 million gain on the sale of a power project under development reported in 2008. The peaking plants reported $2.4 million lower net revenue due primarily to lower power prices in Alberta and $1.2 million higher PPA costs. These decreases were partially offset by lower transmission costs of $7.0 million, $3.0 million due to the commencement of commercial operations at Bear Mountain and $2.3 million of lower environmental costs.

Operating and administrative expense was $6.1 million for 2009 compared to $3.7 million for 2008. The increase was due to costs related to the development of renewable energy projects and increased costs related to the gas-fired peaking plants commissioned in late 2008 and the commencement of commercial operations at Bear Mountain.

Amortization expense was $8.2 million in 2009 compared to $7.4 million in 2008. The increase was due to the gas-fired peaking plants commissioned in late 2008.

Year ended December 31	2009	2008
Volume of power sold (GWh) [1]	2,726	2,623
Average price realized on the sale of power ($/MWh) [1]	68.97	84.51
Alberta Power Pool average spot price ($/MWh) [2]	47.84	89.95

1 Average for the period.
2 Includes only Alberta volumes and prices realized on the sale of power.

CORPORATE

Description of Corporate Assets

The Corporate Segment includes the cost of providing corporate services and general corporate overhead, investments in public and private entities and the effects of changes in the value of risk management assets and liabilities. Management makes operating decisions and assesses performance of its operating segments based on realized results and key financial metrics such as return on equity and return on capital without the impact of the volatility in commodity prices, interest rates and foreign exchange rates. Management monitors the impact of mark-to-market accounting as part of the consolidated entity since risk is managed on a portfolio basis. Consequently, the impact of mark-to-market accounting on net income is reported and monitored in the Corporate Segment.

Corporate Variance A

The operating loss for 2009 was $24.1 million compared to $33.5 million for 2008. The decreased loss was mainly due to realized and unrealized gains from investments, higher investment income and last year's charge for project development costs. These decreases were partially offset by lower unrealized gains on risk management contracts.

Net revenue was $18.6 million in 2009 compared to $12.9 million in 2008. Net revenue increased $13.4 million due to increased investment income, partially offset by $7.7 million in lower unrealized gains on risk management contracts.

Operating and administrative expense was $40.1 million in 2009 compared to $44.1 million in 2008. Increased expenses were incurred to support regulatory requirements and growth of the Trust but were more than offset as a result of several initiatives to reduce general and administrative expenses. The overall decrease was primarily due to these cost-controlling efforts.

Amortization expense was $2.5 million in 2009 compared to $2.2 million in 2008.

Corporate Outlool

Excluding the impact of mark-to-market accounting, the operating loss for 2010 is expected to be higher than the loss reported in 2009. Operating and administrative expenses are expected to be higher than 2009 as a result of the growth of the Trust as well as the cost of converting to a corporation and meeting new financial reporting requirements. The Corporate Segment is also expected to report lower earnings from equity investments since Utility Group is no longer reported as an equity investment.

The effects of risk management contracts are based on estimates relating to commodity prices, interest rates and foreign exchange rates over time. The actual amounts will vary based on these drivers, and management is therefore unable to predict the impact of financial instruments. However, the impact of the accounting standards is expected to be relatively low as the Trust uses financial instruments to manage exposure to commodity price fluctuations and to buy and sell gas and power with locked-in margins. The Trust does not execute financial instruments for speculative purposes.

INVESTED CAPITAI

During 2009, AltaGas acquired capital assets, long-term investments and other assets for $499.2 million compared to $824.8 million in 2008.

Net Invested Capital – Investment Typ

Year ended December 31, 2009 ($ millions)	[illegible]	[illegible]	[illegible]	[illegible]
Invested capital:				
Capital assets	[illegible]	[illegible]	[illegible]	[illegible]
Long-term investments and other assets	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	[illegible]
Disposals:				
Capital assets	[illegible]	[illegible]	[illegible]	[illegible]
Net invested capital	311.5	159.2	27.5	49[illegible]

Year ended December 31, 2008 ($ millions)	Gas Segment	Power Segment	Corporate Segment	Total
Invested capital:				
Capital assets	675.1	141.7	6.6	823.4
Long-term investments and other assets	–	0.7	0.7	1.4
	675.1	142.4	7.3	824.8
Disposals:				
Capital assets	(10.2)	(5.2)	–	(15.4)
Long-term investments and other assets	–	–	(48.2)	(48.2)
Net invested capital	664.9	137.2	(40.9)	761.2

The Trust categorizes its invested capital into maintenance, growth and administration.

Growth capital of $490.1 million was expended in 2009 (2008 – $813.5 million). In the Gas Segment, growth capital comprised $259.1 million for the acquisition of NGD assets, $17.6 million for the Harmattan fractionation project, $14.2 million for the completion of Sarnia Storage, $8.9 million for various E&T projects and $8.4 million for FG&P projects. Within the Power Segment, growth capital projects included $145.6 million for the completion of Bear Mountain Wind Park, $7.9 million for renewable power development projects and $6.4 million related to the Harmattan Cogeneration project. The Corporate Segment growth capital of $22.0 million was related to the acquisition of shares in Magma Energy Corporation. Administrative and maintenance capital expenditures in 2009 were $5.8 million and $3.3 million, respectively (2008 – $7.6 million and $3.7 million, respectively).

Year ended December 31, 2009 ($ millions)	[illegible]	[illegible]	[illegible]	Total
Invested capital:				
Maintenance	[illegible]	[illegible]	[illegible]	[illegible]
Growth	[illegible]	[illegible]	[illegible]	[illegible]
Administrative	[illegible]	[illegible]	[illegible]	[illegible]
Invested capital	[illegible]	[illegible]	[illegible]	[illegible]

Year ended December 31, 2008 ($ millions)	Gas Segment	Power Segment	Corporate Segment	Total
Invested capital:				
Maintenance	3.7	–	–	3.7
Growth	669.0	142.4	2.1	813.5
Administrative	2.4	–	5.2	7.6
Invested capital	675.1	142.4	7.3	824.8

FINANCIAL INSTRUMENTS

The Trust is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. During 2009, the Trust had positions in the following types of derivatives, which are also disclosed on Note 15 to the Consolidated Financial Statements:

Commodity Forward Contracts

The Trust executes gas, power and other commodity forward contracts to manage its asset portfolio and lock in margins from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The Energy Services business transacts primarily on this basis.

Commodity Swap Contracts

The Trust executes fixed-for-floating power price swaps to manage its power asset portfolio. A fixed-for-floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power Segment's results are significantly affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing the Trust's exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $0.10/MWh to $999.99/MWh in 2009 and $0.00/MWh to $999.99/MWh in 2008. The average spot price was $47.84/MWh in 2009 (2008 – $89.95/MWh). AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio. The average price realized for power by the Trust was $68.97/MWh in 2009 (2008 – $84.51/MWh). In 2010, almost two-thirds of the power delivered to the Alberta Power Pool from the Sundance Plant is hedged at a price of $72.00/MWh.

NGL Frac Spread Hedges

The Trust executes fixed-for-floating NGL frac spread swaps to manage its NGL frac spreads. The E&T business' results are affected by fluctuations in NGL frac spreads. In the fourth quarter, the Trust had NGL frac spread agreements for 3,900 Bbls/d for the October to December 2009 period at an average price of approximately $25.17/Bbl. The average spot NGL frac spread for 2009 was $19.51/Bbl (2008 – $28.79/Bbl). The average NGL frac spread realized in 2009 was $23.46/Bbl (2008 – $26.97/Bbl). The Trust has also hedged an average of 2,390 Bbls/d, or approximately 50 percent of volumes that are exposed to spot prices for 2010, at a price of approximately $21/Bbl. In addition, the Trust has hedged 700 Bbls/d, or approximately 15 percent of volumes that are exposed to spot prices for 2011, at a price of approximately $20/Bbl.

Interest Rate Forward Contracts

The Trust enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate. At December 31, 2009 the Trust had interest rate swaps for $185 million with varying terms to maturity until March 31, 2012. At December 31, 2009, the Trust had fixed the interest rate of 68 percent of its debt including MTNs and capital leases.

Foreign Exchange Forward Contracts

Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts whereby a fixed rate is locked in against a floating rate and option agreements whereby an option to transact foreign currency at a future date is purchased or sold.

The fair value of power, natural gas and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. The calculation of fair value of the interest rate derivatives used quoted market rates.

The Trust does not speculate on commodity prices and therefore does not engage in any commodity transactions that create incremental exposure or are based solely on expectations of future energy market price movements. Commodity transactions are used to lock in margins, optimize underlying physical assets or reduce exposure to energy price movements. AltaGas has a risk management group that reviews commodity and credit risk on a daily basis and has created and adheres to a conservative risk policy and hedging program.

At this time AltaGas does not expect any currently known trend or uncertainty to affect the Trust's ability to access its historical sources of cash. MTN offerings during 2009 and credit rating upgrades by DBRS and S&P in 2009 are indications of the Trust's strong financial position and capacity to access financing. Each of the Trust's credit facilities has a maturity date, on which date and absent replacement, extension or renewal, the indebtedness under the respective credit facility becomes repayable. The earliest maturity date for the Trust's credit facilities is August 2010.

Year ended December 31 ($ millions)	2009	2008
Cash from operations	184.1	205.2
Investing activities	(464.1)	(432.7)
Financing activities	265.4	233.4
Change in cash	(14.6)	5.9

Cash from operations reported on the Consolidated Statements of Cash Flows was $184.1 million in 2009 compared to $205.2 million in 2008. The decrease in cash from operations was the result of lower net income, no future income tax recovery and gains on sale of assets in 2009 compared to 2008 and less equity income. These decreases were partially offset by higher unrealized investment income and lower non-cash working capital.

Year ended December 31 ($ millions except current ratio)	2009	2008
Current assets	331.8	363.9
Current liabilities	861.1	323.2
Working capital	(529.3)	40.7
Current ratio	0.39	1.13

Working capital was $(529.3) million at December 31, 2009 compared to $40.7 million at December 31, 2008. The working capital ratio was 0.39 at the end of 2009 compared to 1.13 at the end of 2008. The change is mainly due to the classification of the current portion of long-term debt maturing in 2010 as a current liability.

As of December 31, 2009, the Trust's current portion of long-term debt was $591.9 million. The Trust's management expects to align the timing of the renewal of its credit facilities with the timing of its conversion to a corporation, expected in the second half of 2010. The Trust has begun discussions with current and potential members of the syndicate and does not expect any issues with renewing or increasing its credit facilities.

Cash used for investing activities in 2009 was $464.1 million compared to $433.0 million in 2008. The increase was due to the acquisition of short-term investments and capital assets. A description of the acquisitions and investments related to long-term assets is in the Invested Capital section of this MD&A. Cash used for investing activities reflects the actual cash disbursed for investing activities and may not agree with the amounts in the invested capital sections of the MD&A due to the timing of the actual disbursement of funds and the fact that some acquisitions may be non-cash transactions.

Cash used for financing activities was $265.4 million in 2009 compared to $233.4 million in 2008. The increase in cash was due to the issuance of long-term and revolving debt, distributions paid to unitholders and redemption of convertible debentures.

CAPITAL RESOURCES

The use of debt or equity funding is based on AltaGas' capital structure, which is determined by considering the norms and risks associated with each of its business segments. At December 31, 2009 AltaGas had total debt outstanding of $1,014.7 million, up from $582.0 million as at December 31, 2008. At December 31, 2009 the Trust had $500.0 million in MTNs outstanding and had access to prime loans, base rate loans, LIBOR loans, bankers' acceptances and letters of credit through bank lines amounting to $816.0 million. At December 31, 2009 the Trust had drawn bank debt of $502.0 million and letters of credit outstanding of $51.8 million against the extendible revolving-term letter of credit facility and the demand operating facilities.

As of December 31, 2009, the Trust's current portion of long-term debt was $591.9 million. The Trust's management expects to align the timing of the renewal of its credit facilities with the timing of its conversion to a corporation, expected in the second half of 2010. The Trust has begun discussions with current and potential members of the syndicate and does not expect any issues with renewing or increasing its credit facilities.

On September 16, 2009, AltaGas redeemed its $16.6 million of outstanding 5.85 percent convertible debentures. The debentures were redeemed at $1,000.96 for each $1,000.00 of principal outstanding. The redemption amount was equal to the principal and all accrued and unpaid interest thereon.

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas has been in compliance with these covenants each quarter since the establishment of the facilities. The Trust's earnings interest coverage for the rolling 12 months ended December 31, 2009 was 4.49 times.

Subsequent to the acquisition of Utility Group in fourth quarter 2009, AltaGas increased its target debt-to-total-capitalization ratio from 40 to 45 percent to 45 to 50 percent. The increase is a result of the addition of stable, rate-regulated natural gas distribution assets to the Trust's portfolio of energy infrastructure assets. The Trust's debt-to-total-capitalization ratio at December 31, 2009 was 49.2 percent, up from 37.8 percent at December 31, 2008.

On June 5, 2009, AltaGas filed a Short Form Base Shelf Prospectus to facilitate the issuance of trust units or unsecured debt securities. This shelf has a life of 25 months and permits the Trust to issue up to an aggregate of $500 million of securities. On June 22, 2009, the Trust filed a prospectus supplement establishing AltaGas' MTN program and allowing AltaGas to access the Canadian MTN market when appropriate. As of December 31, 2009, AltaGas had utilized approximately $100 million of the original $500 million available.

Credit Facilities

($ millions)	Borrowing capacity	Drawn at December 31 2009	Drawn at December 31 2008
Demand operating facility	86.0	16.3	2.8
Letter of credit facility	75.0	56.7	68.1
Syndicated credit facility [1]	150.0	–	100.0
Syndicated operating credit facility [2]	375.0	350.8	253.0
Utility Group revolving term credit facility [3]	130.0	130.0	–
	816.0	553.8	423.9

1 Revolving credit facility maturing August 13, 2010.
2 Revolving credit facility maturing September 30, 2010.
3 Revolving credit facility maturing November 17, 2010.

At December 31, 2009 the Trust held a $75.0 million (December 31, 2008 – $75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. At December 31, 2009 the Trust had letters of credit of $46.7 million (December 31, 2008 – $68.1 million) outstanding against the extendible revolving-term letter of credit facility and letters of credit of $5.1 million (December 31, 2008 – $2.8 million) outstanding against the demand operating facilities.

The Trust expects to renew its credit facilities in 2010.

CONTRACTUAL OBLIGATIONS

December 31, 2009 ($ millions)		Payments due by period			
	Total	Less than 1 year	1–3 years	4–5 years	After 5 years
Long-term debt	1,000.1	594.8	100.0	205.3	100.0
Capital leases	7.5	1.9	3.8	1.8	–
Operating leases	62.3	3.3	6.5	6.6	45.9
Purchase commitments	3.2	3.2	–	–	–
Total contractual obligations	1,073.1	603.2	110.3	213.7	145.9

AltaGas entered into a capital lease with Maxim Energy Group Ltd. for the right to 25 MW of gas-fired power-peaking capacity and its related ancillary service and peaking sales revenues. The contract has a 10-year term commencing September 1, 2004 and includes an option at the end of the initial term to extend the term for a further 15 years or to purchase the assets. The net present value of the lease commitment at December 31, 2009 was $7.5 million (December 31, 2008 – $8.8 million), with the balance due in monthly payments comprising principal and interest of $0.2 million.

The Trust has long-term operating lease agreements for gas storage, office space, office equipment and automotive equipment.

[illegible]

As of October 8, 2009, the Trust owned 100 percent of the shares of Utility Group. Therefore, commencing fourth quarter 2009, the Utility Group is not considered a related party. During the first three quarters of 2009, the Trust sold $39.0 million of natural gas to, and incurred transportation costs of $0.1 million charged by, Utility Group as part of the Trust's normal course of business. The Trust also paid management fees of $0.1 million to, and received management fees of $0.1 million, from Utility Group for administrative services. In addition, the Trust provided $0.1 million of operating services to Utility Group. The measurement of transactions between AltaGas and Utility Group is exchange value, to which both parties have agreed. The Trust held significant influence over Utility Group given AltaGas' 19.8 percent ownership, and AltaGas' Chairman and Chief Executive Officer was a director of Utility Group prior to the October 8, 2009 acquisition.

The Trust pays rent under a lease for office space and equipment to 2013761 Ontario Inc., which is owned by an employee. Payments of $90,540 were made in 2009 (2008 – $88,000), which is the exchange value of the property agreed to by both parties. The lease expires December 2011.

RATING AGENCIES

On October 16, 2009, DBRS raised its rating for the Trust from BBB (low) with a Positive trend to BBB with a Stable trend. DBRS has cited the Utility Group acquisition as improving AltaGas' business risk profile through the addition of low-risk, regulated natural gas distribution assets in Alberta, Nova Scotia and the Northwest Territories.

On April 21, 2009 Standard & Poor's (S&P) upgraded its rating for the Trust from BBB- to BBB with a Stable outlook. S&P cited the Trust's increased exposure to long-term contracted gas infrastructure business, prudent financial practices and effective strategy execution for the rating upgrade.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are indicators of the likelihood of repayments and of the capacity and willingness of an entity to meet its financial commitment on an obligation in accordance with the terms of the obligation.

TRUST UNIT INFORMATION

At February 28, 2010 the Trust had 78.8 million trust units and 2.1 million exchangeable units outstanding and a market capitalization of $1.5 billion based on a closing trading price on February 26, 2010 of $18.70 per trust unit. At February 28, 2010 there were 3.8 million options outstanding and 1.2 million options exercisable under the terms of the unit option plan.

DISTRIBUTIONS

AltaGas distributions are determined giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, maintenance and growth capital expenditures and debt repayment requirements of the Trust. AltaGas has been able to sustain its distributions through funds from operations. In 2009, the Trust declared distributions of $170.2 million and had funds from operations of $202.3 million (2008 – $147.1 million and $217.1 million, respectively), or a payout ratio of 84 percent (2008 – 68 percent).

The Board of Directors of AltaGas General Partner Inc., delegate of the Trustee, maintained the Trust's monthly cash distribution at $0.18 per unit ($2.16 per unit annualized) for 2009. AltaGas pays cash distributions on the 15th day of each month to unitholders of record on the 25th day of the previous month or, in each case, the following business day if the payment or record date falls on a weekend or holiday.

The following table summarizes AltaGas' distribution declaration history since 2007:

Distributions

Years ended December 31

($ per unit)	2009	2008	2007
First quarter	0.540	0.525	0.510
Second quarter	0.540	0.525	0.510
Third quarter	0.540	0.535	0.520
Fourth quarter	0.540	0.540	0.525
Distribution of shares [1]	–	–	0.076
Total	2.160	2.125	2.141

1 On September 17, 2007 one share of Utility Group was issued for every 100 trust units and exchangeable units held on August 27, 2007.

Assuming a unit was held throughout 2009, for income tax purposes, the Trust expects 78.8 percent of the total distributions declared in 2009 to be taxed as income, 4.0 percent as capital gains, 0.2 percent as dividend income and 17.0 percent as return of capital. For most unitholders, the return of capital amount will reduce the cost base of their Trust units for purposes of calculating the capital gains amount upon disposition of their units. Unitholders should seek independent tax advice in respect of the consequences to them of acquiring, holding and disposing of units.

CORPORATE CONVERSION

AltaGas expects to convert to a corporation in the second half of 2010 in response to the Government of Canada's changes to the tax treatment of income trusts effective January 1, 2011. In 2009, federal legislation was enacted for the conversion of income trusts in which the trust is able to convert to a corporation without triggering adverse tax consequences to the trust or its unitholders.

AltaGas expects to continue to implement its growth strategy, while seeking to provide investors with a balance between income and growth. As a corporation, AltaGas' management expects to pay a dividend between $1.10 and $1.40 per share on an annual basis to support the Trust's growth strategy going forward. At the time of conversion, the Board of Directors will approve the dividend policy subject to economic and financial conditions at that time. Until its anticipated conversion, AltaGas expects to continue to pay a monthly distribution of $0.18 per trust unit.

AltaGas has always executed its strategy as a tax-efficient corporate and focused on key traditional financial metrics such as earnings per unit and return on equity. It does not rely on the trust structure to sustain its business.

AltaGas has entered into a non-monetary transaction with a third party in which it exchanged B.C. Renewable Energy Certificates (RECs) for verified emission offsets that were generated in Alberta. The RECs will be created through the generation of power at the Bear Mountain Wind Park between 2009 and 2011. The verified emission offsets received by AltaGas were used to offset the costs to comply with SGER in 2009.

On January 1, 2010 AltaGas issued 180,433 units on exercise of special warrants that were originally issued in February 2008 on a one-for-one basis at $24.94 per special warrant.

On February 2, 2010 AltaGas offered to acquire all the outstanding common shares of Landis Energy Corporation (Landis) in exchange for cash of $0.80 per common share. The acquisition is valued at approximately $22 million and, if successful, will be funded through AltaGas' existing credit facilities. The offer is subject to certain conditions, including its acceptance by the holders of at least two-thirds of the outstanding common shares of Landis and regulatory approval. The offer is currently due to expire on March 10, 2010.

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2008, the new Canadian Institute of Chartered Accountants (CICA) Handbook Section 3064 "Goodwill and Intangible Assets" will replace Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets, including internally generated intangible assets. The adoption of this standard did not have a material impact on the Consolidated Financial Statements for the year ended December 31, 2009.

In January 2009, the EIC reached a consensus that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Accordingly, the Trust was required to fair value derivative instruments, at the beginning of the period of adoption, to take into account both own credit risk and counterparty credit risk. Any resulting difference has been recorded as an adjustment to retained earnings with the exception of cash flow hedges, which have been recorded in accumulated other comprehensive income.

In accordance with CICA Handbook Section 3863 "Financial Instruments – Presentation", the Trust changed its presentation of derivative financial assets and financial liabilities to report the net amount in the balance sheet where AltaGas has a legally enforceable right to offset the recognized amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously. Accordingly, the Trust's comparative balances have been reclassified to reflect the change in accounting policy. For the impact on the Trust's financial statements on adopting EIC-173, see note 2 to the interim Consolidated Financial Statements for the year ended December 31, 2009.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS

The Accounting Standards Board (AcSB) confirmed in February 2009 that IFRS will replace Canadian GAAP for publicly accountable enterprises for financial periods beginning on or after January 1, 2011.

AltaGas commenced a process to transition from Canadian GAAP to IFRS in April 2008. AltaGas has established a project team that is led by Finance management and includes representatives from various areas of the organization as necessary to plan for and achieve a smooth transition to IFRS. Regular progress reporting to the Audit Committee of the Board of Directors on the status of the IFRS implementation project has been instituted and enacted.

The implementation project consists of six phases, which in certain cases will be in process concurrently as IFRS are applied to specific areas from start to finish:

Scoping phase This phase involves a high-level assessment to identify key areas impacted by the transition to IFRS and to identify the Standards and Interpretations applicable to the Trust. This phase was completed in July 2008.

Diagnostic phase In this phase, each Standard and Interpretation is assessed to identify the changes required in the existing accounting policies, information systems and business processes. An IFRS mock-financial statement has been prepared for further guidance in the conversion process. This phase was completed in December 2008.

Design and planning phase Available alternatives in the accounting policies, elective exemptions and mandatory exceptions are assessed and adopted. Evaluation of the quantitative impact from the IFRS adoption is in progress.

Solution development phase Based on the adopted accounting policies, the project team defines and develops systems, processes and training required for the implementation of the target solutions under IFRS. The evaluation of the quantitative impact from IFRS adoption is in progress.

Implementation phase During the dual reporting period from January 1 until December 31, 2010, changes in accounting policies and procedures are executed and tested. Financial information in accordance with IFRS is collected, enabling the comparative reporting in 2011. Where possible, the CEO/CFO certification will start and the risk control assessment matrix will be updated accordingly. Training is provided at different levels with emphasis on the areas more impacted by IFRS adoption.

Post-implementation phase IFRS financial statements are produced for each reporting period. External auditors are requested to provide their opinion on the compliance of the financial statements with IFRS requirements. CSOX certification process is fully deployed for the IFRS conversion in compliance with the disclosure controls and procedures (DC&P). The achieved results are compared with the target objectives, including enhancing the effectiveness of financial reporting, to confirm whether the project has been successful and consequently can be closed.

There are currently no delays anticipated to AltaGas' project plan to meet IFRS reporting requirements in 2011.

[illegible]

IFRS 1 "First time adoption of International Financial Reporting Standards" provides entities adopting IFRS for the first time with a number of elective exemptions and mandatory exceptions, in certain areas, to the general requirement for a full retrospective application of IFRS. Similarly, other Standards provide for an accounting choice that has been assessed and elected prospectively from January 1, 2010, the transition date to IFRS. AltaGas is in the process of evaluating the standards and policy choices.

[illegible]

Compensation arrangement Incentive schemes shall be tested under IFRS financial results during the transition period to verify any impacts. If necessary, compensation arrangements will be renegotiated before the end of 2010.

[illegible] Internal Control Framework

- A risk assessment on disclosure controls and procedures and internal control framework has been initiated during 2010.
- The alignment between the IFRS conversion and the certification processes started during the design and planning phase and is considered a test for the quality and completeness of the IFRS implementation.

[illegible]

The Trust will monitor the changes in the standards throughout the dual reporting period for adopting, where necessary, amendments to the implementation plan. According to the International Accounting Standards Board (IASB) work plan, the following changes are foreseen to be issued in the near future:

- Joint arrangements (Q1 2010)
- Liabilities and provisions (Q3 2010)
- Emission trading schemes (Q1 2011)
- Fair value measurement guidance (Q3 2010)
- Impairment financial instruments (Q4 2010)
- Hedge accounting (Q3 2010)
- Derecognition financial instruments (Q3 2010)
- Rate-regulated activities (Q2 2010)
- Leases (Q1 2011)
- Consolidation (Q3 2010)

Contingency plans have been developed to track and incorporate subsequent changes as a result of changes in accounting standards. Where permitted by the standards and appropriate, these changes will be effective from January 1, 2010.

[illegible]

AltaGas had initiated discussions with the external auditors around the IFRS opening balances and the timing and review of these values. It is expected that the timing will be confirmed early in 2010 after the year-end has been completed and any final entries required for the opening balances finalized.

At this time, it is not possible to reasonably quantify the effects of IFRS to the Trust's Consolidated Financial Statements. AltaGas will provide additional disclosures of the key elements of the plan and progress of the project as the information becomes available.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Trust's Consolidated Financial Statements requires the use of estimates and assumptions that have been made using careful judgment. AltaGas' significant accounting policies are contained in the notes to the Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

AltaGas' critical accounting estimates continue to be amortization expense, asset retirement obligations, asset impairment assessment, income taxes, pension and rate-regulated assets and liabilities. The following section describes the critical accounting estimates and assumptions that AltaGas has made and how they affect the amounts reported in the Consolidated Financial Statements.

Amortization

AltaGas performs assessments of amortization of capital assets and energy services arrangements, contracts and relationships. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. Oil and gas capitalized costs are depleted (amortized) to income on a unit-of-production basis over the estimated production life of proved reserves. Amortization is a critical accounting estimate because:

- There are a number of uncertainties inherent in estimating the remaining useful life of certain assets;
- There is also uncertainty related to assumptions about reserve quantities; and
- Changes in these assumptions could result in material adjustment to the amount of amortization that the Trust recognizes from period to period.

Asset Retirement Obligations and Other Environmental Cost

The Trust records liabilities relating to asset retirement obligations and other environmental matters. Asset retirement obligations and other environmental costs are critical accounting estimates because:

- The majority of the asset retirement costs will not be incurred for a number of years (most are estimated between 2045 and 2060), requiring the Trust to make estimates over a long period of time;
- Environmental laws and regulations could change, resulting in a change in the amount and timing of expenses anticipated to be incurred; and
- A change in any of these estimates could have a material impact on the Trust's Consolidated Financial Statements.

Asset Impairment

AltaGas reviews long-lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. This is a critical accounting estimate because:

- It requires management to make assumptions about future cash inflows and outflows over the life of an asset, which are susceptible to changes from period to period due to changing information available related to the determination of the assumptions; and
- The impact of recognizing an impairment may be material to the Trust's Consolidated Financial Statements.

With respect to impairment assessment, management has made fair-value determinations related to goodwill, estimating future cash flows as well as appropriate discount rates. The estimates have been applied consistent with prior periods.

The Trust and its Canadian subsidiaries are (in addition to local tax rules applicable to their foreign subsidiaries) subject to a regime of specialized rules prescribed under the Income Tax Act (Canada) for purposes of determining the amount of the Trust's and its subsidiaries' income that will be subject to tax in Canada. Accordingly, the determination of the Trust's and its subsidiaries' provision for income taxes involves the application of these complex rules in respect of which alternative interpretations may arise. Management of the Trust and its subsidiaries recognize that interpretations they may make in connection with tax filings may ultimately differ from those made by the tax authorities. Tax planning may allow the entities to record lower income taxes in the current year, and, as well, income taxes recorded in prior years may be adjusted in the current year to reflect management's best estimates of the overall adequacy of the provisions.

Substantial future income tax assets are recognized in the Consolidated Financial Statements of the Trust. The recognition of future tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. The amount of the future tax asset or liability recorded is based on management's best estimate of the timing of the realization of the assets or liabilities.

If management's interpretation of tax legislation differs from that of local tax authorities or if timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. See note 12 to the Consolidated Financial Statements.

The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on plan assets and the discount rate applied to pension plan obligations. For post-retirement benefit plans, which provide for certain health care premiums and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining post-retirement obligations and expense are the discount rate and the assumed health care cost-trend rates. Notes 2 and 22 to the Consolidated Financial Statements include information on the assumptions used for the purposes of recording the funding status of the plans and the associated expenses.

AltaGas acquired AltaGas Utilities Inc. (AUI) and Heritage Gas Limited (Heritage Gas) in the acquisition of AltaGas Utility Group Inc. (Utility Group) (note 3), which also owns one-third of Inuvik Gas Ltd. (Inuvik Gas). AUI and Heritage Gas and Inuvik Gas engage in the delivery and sale of natural gas and are regulated by the Alberta Utilities Commission (AUC) and the Nova Scotia Utility and Review Board (NSUARB) and the Northwest Territories Public Utilities Board (NWTPUB), respectively. The AUC and NSUARB exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns, accounting and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the AUC and NSUARB, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using GAAP for entities not subject to rate regulation. Inuvik Gas is subject to light-handed regulation by the NWTPUB, whereby rates are set by Inuvik Gas based on competitive market price. Inuvik Gas is required to file its rates, terms and conditions of service with NWTPUB when they are revised. The NWTPUB can take action should any complaints be received and may review the affairs, earnings and accounts of Inuvik Gas as it deems necessary.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that will be recovered from customers in future periods though the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are to be refunded to customers through the rate-setting process.

OFF-BALANCE-SHEET ARRANGEMENTS

The Trust is not party to any contractual arrangement under which an unconsolidated entity may have any obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. The Trust has no obligation under derivative instruments, or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services with the Trust.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Trust is responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The objective of this instrument is to improve the quality, reliability and transparency of information that is filed or submitted under securities legislation.

The Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of the Trust's employees, DC&P to provide reasonable assurance that material information relating to the Trust is made known to them and information required to be disclosed by the Trust in its annual filings, interim filings and other documents filed or submitted under securities legislation are recorded, processed, summarized and reported within the time periods specified in securities legislation.

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of the Trust's employees, the effectiveness of the Trust's DC&P and, based on that evaluation, have concluded that the Trust's DC&P was effective at December 31, 2009.

The Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of the Trust's employees, ICFR to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with Canadian GAAP.

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of the Trust's employees, the effectiveness of the Trust's ICFR based on the framework established by the Committee of Sponsoring Organizations (COSO) and have concluded that the Trust's ICFR was effective at December 31, 2009 based on that evaluation.

During 2009 there were no changes made to the Trust's ICFR that materially affected, or are reasonably likely to materially affect, the Trust's ICFR.

FOURTH QUARTER HIGHLIGHTS

Net income for fourth quarter 2009 was $32.1 million compared to $39.6 million in the same period in 2008. Net income was $0.40 per basic unit for fourth quarter 2009 compared to $0.55 per basic unit for the same period in 2008.

Fourth quarter 2009 was a successful quarter for AltaGas due to the completion of the Utility Group and Heritage Gas acquisitions (natural gas distribution assets) and Bear Mountain Wind Park commencing commercial operations. All of these achievements immediately contribute to the Trust's operating income.

During the quarter, the Gas Segment performed well due to the addition of the NGD assets, contributions from Sarnia Storage, adjustment to transmission revenues previously deferred, higher fee-for-service revenues and the expiry of a legacy gas marketing contract. These increases were partially offset by lower processing volumes at FG&P facilities as producers reduced drilling activities and shut-in production in response to weak gas prices and lower realized frac spread prices. The Power Segment reported lower results primarily due to higher volumes sold at low spot power prices but benefited from lower transmission and environmental costs, as well as contributions from Bear Mountain Wind Park, which commenced commercial operations in fourth quarter 2009. Higher investment income offset operating costs in the Corporate Segment. The Corporate Segment reported unrealized losses on risk management contracts compared to unrealized gains in fourth quarter 2008. The Trust reported higher interest expense in fourth quarter 2009 compared to the same period in 2008 due to higher average debt balances, partially offset by a lower average borrowing rate. Income tax expense was lower in fourth quarter 2009 due to the impact for financial instruments and lower income subject to tax.

On a consolidated basis, net revenue for fourth quarter 2009 was $115.4 million compared to $125.8 million in same period 2008. In the Gas Segment, net revenue increased due to the acquisition of NGD assets, higher fee-for-service revenues, contributions from Sarnia Storage, increased rates, expiry of a legacy gas marketing contract, higher frac spreads and NGL volumes and higher transmission fees. These increases were partially offset by lower throughput in most FG&P areas and lower operating cost recoveries. In the Power Segment, net revenue decreased due to lower revenue from the sale of power in Alberta at spot power prices, which were lower than the same period last year, the gain on assets sold in 2008 and lower contribution from gas-fired peaking plants, partially offset by the contribution from Bear Mountain Wind Park, strong hedge prices and lower PPA costs. The Corporate Segment reported higher net revenue due to investment income, partially offset by unrealized losses on risk management contracts.

Operating and administrative expense for fourth quarter 2009 was $56.4 million, up from $56.1 million for same period 2008. The increase was due to the addition of NGD assets partially offset by lower costs within the Corporate Segment.

Amortization expense for fourth quarter 2009 was $20.3 million compared to $16.8 million in the same period 2008. The increase was due to the growth in AltaGas' asset base from acquisitions and construction activities.

Interest expense in fourth quarter 2009 was $9.3 million compared to $8.1 million for the same period 2008. The increase was due to higher average debt balances of $945.3 million compared to $581.6 million for the same period in 2008. The average debt balance was higher due to the Utility Group and Heritage Gas acquisitions in the fourth quarter. The increase was partially offset by a lower average borrowing rate. The average borrowing rate was 4.9 percent in fourth quarter 2009 compared to 6.3 percent in fourth quarter 2008.

In fourth quarter 2009, an income tax recovery of $2.9 million was reported compared to an expense of $6.4 million in fourth quarter 2008. The decrease was due to the impact for financial instruments and lower income subject to tax.

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2009 net income:

Factor share	Increase or decrease	Increase or decrease in net income per unit
Gathering and processing volumes	5 Mmcf/d	0.012
Gathering and processing operating margin per Mcf	1¢/Mcf	0.022
Alberta electricity prices [1]	$1/MWh	0.006
Natural gas liquids fractionation spread [2]	$1 per Bbl	0.008
Interest rates	25 bps	0.008
Degree days [3]	5 percent	0.006

1 Based on 70 percent of PPA volumes being hedged.
2 Based on 60 percent of frac spread exposed NGL volumes being hedged.
3 Degree day variance is a measure of the temperature of the geographic areas in which AUI operates, over the applicable period expressed in relation to normal degree days in that period. A degree day is the cumulative extent to which the day mean temperature falls below 15°C. Normal degree days are based on a 20-year rolling average.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS

	2009				2008			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	336.4	291.4	285.8	354.6	424.6	460.7	487.1	444.5
Net revenue [1]	115.4	114.7	114.3	112.1	125.8	122.7	117.3	110.7
Operating income [1]	38.8	45.4	45.5	44.7	54.1	50.7	37.0	47.6
Net income	32.1	34.7	36.9	37.5	39.6	53.5	32.9	37.6

	2009				2008			
($ per unit)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Net income								
Basic	0.40	0.44	0.47	0.50	0.55	0.75	0.49	0.58
Diluted	0.40	0.43	0.46	0.49	0.56	0.75	0.49	0.57
Distributions declared	0.54	0.54	0.54	0.54	0.54	0.535	0.525	0.525

1 Non-GAAP financial measure. See Non-GAAP Financial Measures.

Identifiable trends in AltaGas' business in the past eight quarters reflect the organization's internal growth, acquisitions, generally increasing power prices in Alberta until 2009, higher NGL frac spreads through most of 2008, increased volatility in commodity prices in recent quarters and asset dispositions.

Significant items that impacted individual quarterly earnings were as follows:

- In fourth quarter 2007, a $6.1 million non-cash future income tax benefit was recorded as a result of the substantive enactment of a reduction in the federal corporate income tax rates.
- In first quarter 2008, the Taylor acquisition was completed for total consideration of $455.2 million, of which $256.3 million was cash consideration and $198.9 million was for units issued. Results in first quarter 2008 increased as a result of the Taylor acquisition.
- In second quarter 2008, operating income was affected by major turnarounds within the gas business and one-time charge to expense project development costs.
- In third quarter 2008, AltaGas recognized an income tax recovery of $13.8 million related to the reduction of future income tax liabilities, which was a result of the reorganization of legal entities within the Trust's structure and required the use of lower effective tax rates.
- In third quarter 2008, operating income was negatively impacted by two extraction plant turnarounds and unplanned outage due to a natural gas heater fire at the Harmattan Complex.
- In latter part of fourth quarter 2008 and during the first half of 2009, prices for power, natural gas and NGLs declined, breaking the historical price trend for these products. Reduced natural gas prices have directly affected the activity of producers within the WCSB.
- In second quarter 2009, the Trust purchased a short-term investment that resulted in an unrealized gain of $4.6 million.
- During 2009, the Trust has adjusted liabilities related to natural gas transaction within Energy Services resulting in a one-time revenue impact of $9.2 million.
- During fourth quarter 2009, Bear Mountain was fully connected to the B.C. power grid and met the conditions for commercial operations in order to receive the firm price under the 25-year energy purchase agreement with BC Hydro.
- Acquired all the outstanding common shares of Utility Group not previously held by AltaGas for $204.5 million including assumed debt.
- Acquired the 75.1 percent it did not already own of the outstanding shareholder loans and common shares of Heritage Gas Limited (Heritage Gas) for $111.0 million.

Consolidated Financial Statements

Management's Responsibility for Financial Statements

Management recognizes that it is responsible for the preparation of the Consolidated Financial Statements and is satisfied that these statements have been prepared using Canadian generally accepted accounting principles and are within reasonable limits of materiality. The internal controls and systems of AltaGas Income Trust (AltaGas or the Trust) are designed to provide reasonable assurance that the Trust's assets are safeguarded and to facilitate the preparation of relevant, reliable and timely information. Independent auditors have been engaged by the Trust to examine the Consolidated Financial Statements. The Consolidated Financial Statements are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors is composed of directors who are not officers or employees. The Consolidated Financial Statements and MD&A are discussed and reviewed by the Audit Committee with management and the independent auditors before such information is approved by the Committee and recommended to the Board of Directors for approval. The Board of Directors, on the recommendation of the Audit Committee, has approved the Consolidated Financial Statements in this report.

DAVID W. CORNHILL
Chairman and Chief Executive Officer
of AltaGas General Partner Inc.,
delegate of the Trustee of AltaGas Income Trust

February 25, 2010

DEBORAH S. STEIN
Vice President Finance and Chief Financial Officer
of AltaGas General Partner Inc.,
delegate of the Trustee of AltaGas Income Trust

February 25, 2010

Auditors' Report

To the Unitholders of AltaGas Income Trust

We have audited the consolidated balance sheets of AltaGas Income Trust as at December 31, 2009 and 2008 and the consolidated statements of income and accumulated earnings, comprehensive income and accumulated other comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of AltaGas Income Trust as at December 31, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

ERNST & YOUNG, LLP
Chartered Accountants

February 23, 2010
Calgary, Canada

Consolidated Balance Sheets

As at December 31 ($ thousands)	2009	2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 3,739	$ 18,304
Short-term investment (note 15)	19,436	–
Accounts receivable	203,673	220,280
Inventory	1,401	775
Restricted cash holdings from customers	27,228	24,017
Regulatory assets (note 4)	2,567	–
Risk management (note 15)	66,271	92,842
Prepaid expense and other current assets	7,505	7,705
	331,820	363,923
Capital assets (note 5)	1,857,095	1,436,686
Energy arrangements, contracts and relationships (note 6)	128,949	138,913
Goodwill (note 7)	201,728	143,840
Regulatory assets (note 4)	60,885	–
Risk management (note 15)	18,132	31,147
Long-term investments and other assets (note 8)	30,487	17,744
	$ 2,629,096	$2,132,253
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 158,319	$ 198,232
Distributions payable to unitholders	15,110	12,943
Short-term debt (note 9)	14,626	4,493
Current portion of long-term debt (note 10)	591,944	1,363
Customer deposits	30,678	24,017
Deferred revenue	–	2,777
Regulatory liabilities (note 4)	1,403	–
Risk management (note 15)	34,200	57,423
Other current liabilities	14,830	21,927
	861,110	323,175
Long-term debt (note 10)	408,170	559,412
Asset retirement obligations (note 12)	41,771	41,708
Future income taxes (note 13)	228,596	211,256
Regulatory liabilities (note 4)	16,610	–
Risk management (note 15)	14,491	16,745
Convertible debentures (note 11)	–	16,682
Future employee obligations (note 22)	9,491	5,833
	1,580,239	1,174,811
Unitholders' equity (notes 16, 17 and 18)	1,048,857	957,442
	$ 2,629,096	$2,132,253

Commitments and contingency (notes 9, 10, 15, 20, 22 and 26)

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas General Partner Inc. on behalf of AltaGas Income Trust:

David Cornhill

DAVID W. CORNHILL
Director

Robert B. Hodgins

ROBERT B. HODGINS
Director

Consolidated Statements of Income and Accumulated Earnings

For the years ended December 31

($ thousands except per-unit amounts)	2009	2008
REVENUE		
Operating	$ 1,249,649	$1,803,928
Unrealized gain on risk management (note 15)	3,697	10,986
Other (notes 11 and 15)	14,919	1,881
	1,268,265	1,816,795
EXPENSES		
Cost of sales	811,688	1,340,318
Operating and administrative	208,219	221,500
Amortization:		
Capital assets	64,157	57,075
Energy arrangements, contracts and relationships	9,964	9,903
	1,094,028	1,628,796
Foreign exchange gain (loss)	(1)	1,369
Interest expense		
Short-term debt	1,283	2,632
Long-term debt	30,476	24,767
Income before income taxes	142,477	161,969
Income tax expense (recovery) (note 13)		
Current income tax	981	2,328
Future income tax	187	(3,930)
Net income	141,309	163,571
Accumulated earnings, beginning of year (note 2)	673,736	510,412
Accumulated earnings, end of year	$ 815,045	$ 673,983
Net income per unit (note 19)		
Basic	$ 1.80	$ 2.38
Diluted	$ 1.79	$ 2.36
Weighted average number of units outstanding (thousands) (notes 17 and 19)		
Basic	78,540	68,813
Diluted	79,371	69,704

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income and Accumulated Other Comprehensive Income

For the years ended December 31

($ thousands)	[illegible]	2008
Net income	[illegible]	$ 163,571
Other comprehensive income (loss), net of tax		
Unrealized net gain on available-for-sale financial assets	[illegible]	–
Unrealized net gain on derivatives designated as cash flow hedges	[illegible]	20,560
Reclassification of available-for-sale financial assets as a result of business acquisition		(17,873)
Reclassification to net income of net gain (loss) on derivatives designated as cash flow hedges pertaining to prior periods	[illegible]	1,686
	[illegible]	4,373
Comprehensive income	[illegible]	$ 167,944
Accumulated other comprehensive income (loss), beginning of year	[illegible]	$ 27,169
Other comprehensive income (loss), net of tax	[illegible]	4,373
Accumulated other comprehensive income, end of year (note 15)	[illegible]	$ 31,542

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the years ended December 31

($ thousands)	[illegible]	2008
Cash from operations		
Net income	$ 141,309	$ 163,571
Items not involving cash:		
Amortization	74,121	66,978
Accretion of asset retirement obligations (note 12)	3,138	2,302
Unit-based compensation	(195)	387
Future income tax expense (recovery) (note 13)	187	(3,930)
Gain on sale of assets	(28)	(2,045)
Equity income	(158)	(1,388)
Unrealized gain	(9,468)	(10,986)
Goodwill impairment (note 7)	150	100
Other	2,788	1,801
Non-operating investment income	(9,585)	–
Asset retirement obligations settled (note 12)	(384)	(744)
Net change in non-cash working capital (note 21)	(17,729)	(10,891)
	[illegible]	205,155
Investing activities		
Increase (decrease) in customer deposits	(3,211)	352
Decrease in notes receivable	–	6,500
Capital expenditures	(242,970)	(143,928)
Disposition of capital assets	–	15,618
Investment in regulatory assets	(6,014)	–
Distributions from equity investments	3,236	291
Acquisition of short-term investment	(8,198)	–
Business acquisition (note 3)	(191,277)	(311,493)
Acquisition of long-term investments and other assets	(15,658)	–
	[illegible]	(432,660)
Financing activities		
Repayment of short-term debt	10,133	942
Net issuance of revolving long-term debt	16,132	233,985
Issuance of long-term debt	295,080	–
Repayment of long-term debt	(18,017)	(5,792)
Distributions to unitholders	(168,666)	(144,348)
Net proceeds from issuance of units	130,719	144,071
Net proceeds from issuance of warrants	–	4,500
	[illegible]	233,358
Change in cash and cash equivalents	(14,565)	5,853
Cash and cash equivalents, beginning of year	18,304	12,451
Cash and cash equivalents, end of year	[illegible]	$ 18,304

See accompanying notes to the Consolidated Financial Statements.

Notes to the Consolidated Financial Statements

(Tabular amounts and amounts in footnotes to tables are in thousands of dollars unless otherwise indicated.)

STRUCTURE OF ALTAGAS INCOME TRUST

AltaGas Income Trust (AltaGas or the Trust) is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to a Declaration of Trust dated March 26, 2004. The Trust indirectly holds all of the assets, liabilities and businesses formerly held by AltaGas Services Inc. (ASI).

IMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These Consolidated Financial Statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Significant accounting policies are summarized below:

SIS OF PRESENTATION

These Consolidated Financial Statements include the accounts of AltaGas Income Trust and all of its wholly owned subsidiaries, and its proportionate interests in various partnerships and joint ventures, including the Edmonton Ethane Extraction Plant, Empress ATCO Extraction Plant, Empress Provident Extraction Plant, Younger Extraction Plant, Sarnia Airport Storage Pool Limited Partnership, ASTC Power Partnership (ASTC), Inuvik Gas Ltd. (Inuvik Gas) and Ikhil Joint Venture. Transactions between the Trust and its wholly owned subsidiaries and the proportionate interests are eliminated on consolidation.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2009 the Trust adopted Emerging Issues Committee (EIC) 173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities" and the new Canadian Institute of Chartered Accountants (CICA) Handbook accounting requirements for Section 3064 "Goodwill and Intangible Assets". In accordance with the transitional provisions for these new standards, these policies were adopted retrospectively without restatement of prior periods.

Effective October 8, 2009 the Trust adopted the changes to Section 1100 "Generally Accepted Accounting Principles" and Section 3465 "Income Taxes" related to the recognition and measurement of assets and liabilities arising from rate regulation. The Trust adopted these standards as a result of the acquisition of AltaGas Utility Group Inc. (Utility Group) (note 3).

Effective December 31, 2009 the Trust adopted the revisions to Section 3862 "Financial Instruments – Disclosures". This policy was adopted retrospectively.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

In January 2009, the EIC reached a consensus that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Accordingly, the Trust was required to fair value derivative instruments, at the beginning of the period of adoption, to take into account both its own credit risk and counterparty credit risk. Any resulting difference has been recorded as an adjustment to retained earnings with the exception of cash flow hedges, which have been recorded in accumulated other comprehensive income.

In accordance with CICA Handbook Section 3863 "Financial Instruments – Presentation", the Trust changed its presentation of derivative financial assets and financial liabilities to report the net amount in the balance sheet where AltaGas has a legally enforceable right to offset the recognized amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously. Accordingly, the Trust's comparative balances have been reclassified to reflect the change in accounting policy.

The net effect on the Trust's financial statements as at January 1, 2009 resulting from the above-mentioned changes is as follows:

Balance sheet account affected	Increase (Decrease)
Current assets – risk management	(25,772)
Long-term assets – risk management	(5,983)
Current liabilities – risk management	(25,421)
Long-term liabilities – risk management	(5,900)
Future income taxes	(285)
Unitholders' equity – accumulated earnings	(176)
Unitholders' equity – accumulated other comprehensive income	27

The unrealized gains and losses included in accumulated earnings and accumulated other comprehensive income were recorded net of income tax recovery of $287,645 and expense of $2,629, respectively.

Goodwill and Intangible Assets

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2008, the new CICA Handbook Section 3064 replaces Section 3062 "Goodwill and Other Intangible Assets", which included the old Section 3450 "Research and Development Costs" that was transferred in February 2008. This Section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets, including internally generated intangible assets. This new section is effective for the Trust beginning January 1, 2009. There was no financial impact to AltaGas' financial statements as a result of these changes.

Goodwill represents that portion of the purchase price on acquisition that was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but is tested at least annually for impairment by comparing the fair value of the reporting unit with its book value. If the carrying value of the reporting unit exceeds fair value, the fair value of goodwill is determined. Any excess of the carrying value of goodwill over its fair value is recorded as an impairment charge to income.

Intangible assets are initially recorded at cost, including costs directly attributable to acquiring, creating, producing and preparing the intangible asset to be capable of operating in the manner intended. An intangible asset that is capable of operating in the manner intended is amortized to income on a straight-line basis over the estimated useful life, unless it is determined to have an infinite life. Intangible assets are tested at least annually for impairment by comparing the fair value of the reporting unit with its book value. If the carrying value of the reporting unit exceeds fair value, the implied fair value of the intangible asset is determined. Any excess of the carrying value of intangible assets over its implied fair value is recorded as an impairment charge to income.

Financial Instruments – Disclosures

Effective for annual financial statements for fiscal years ending after September 30, 2009, the CICA revised standards under Handbook Section 3862 "Financial Instruments – Disclosures". The revisions require additional disclosure based on a fair value hierarchy that reflects the significance of the inputs used in measuring fair value. Financial assets and financial liabilities with fair value measurement based on quoted prices (unadjusted) in active markets are included in Level 1, inputs other than quoted prices that are observable either directly or indirectly in Level 2 and inputs that are not based on observable market data in Level 3. The disclosure requirements are effective for the Trust beginning December 31, 2009. The additional information to comply with these standards is disclosed in note 16.

Rate-regulated Assets and Liabilities

Effective for the Trust on October 8, 2009, the revisions to CICA Handbook Section 1100 "Generally Accepted Accounting Principles" pertain to the recognition and measurement of assets and liabilities arising from rate regulation. As a result of adopting these changes, the Utility Group, an indirect wholly owned subsidiary of AltaGas, reclassified $16.3 million of reserves for future removal and site restoration costs previously netted against capital assets to non-current regulatory liabilities.

Effective for the Trust on October 8, 2009, the revisions to CICA Handbook Section 3465 "Income Taxes" require the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future tax rates and recovered from or paid to future customers. As a result of adopting these changes, Utility Group, an indirect wholly owned subsidiary of AltaGas, recognized $11.3 million of previously unrecognized future income tax liabilities and an offsetting regulatory asset.

All business combinations are accounted for using the purchase method. Under the purchase method, assets and liabilities of the acquired entity are recorded at fair value. The excess of the purchase price over the fair value of the assets and liabilities acquired is recorded as goodwill.

AltaGas acquired AltaGas Utilities Inc. (AUI) and Heritage Gas Limited (Heritage Gas) in the acquisition of Utility Group (note 3), which also owns one-third of Inuvik Gas. AUI, Heritage Gas and Inuvik Gas engage in the delivery and sale of natural gas and are regulated by the Alberta Utilities Commission (AUC), the Nova Scotia Utility and Review Board (NSUARB) and the Northwest Territories Public Utilities Board (NWTPUB), respectively. The AUC and NSUARB exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns, accounting and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the AUC and NSUARB, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using GAAP for entities not subject to rate regulation. Inuvik Gas is subject to light-handed regulation by the NWTPUB, whereby rates are set by Inuvik Gas based on competitive market price. Inuvik Gas is required to file its rates, terms and conditions of service with NWTPUB when they are revised. The NWTPUB can take action should any complaints be received and may review the affairs, earnings and accounts of Inuvik Gas as it deems necessary.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that will be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are to be refunded to customers through the rate-setting process.

See note 4 for a description of the financial statement effects of rate regulation.

Cash and cash equivalents consist of cash on hand and balances with banks and investments in money market instruments with original maturities of less than three months.

Short-term investments are highly liquid investments with no contractual maturities. Short-term investments are recorded at fair value based on quoted market prices, with changes in fair value recorded in other revenue.

Inventory consists of materials and supplies and natural gas liquid (NGL) product held for sale. All inventories are valued at the lower of cost or net realizable value. Cost is assigned using a weighted average cost formula.

Cash deposited by customers under the terms of natural gas and power agency arrangements is invested in short-term deposits with a Canadian chartered bank. These funds are restricted and are not available for general use by the Trust. Any corresponding liability is classified as customer deposits within current liabilities.

Capital Assets and Amortization

Capital assets are recorded at cost plus interest incurred during the construction period to finance long-term construction projects. Major renewals or betterments are included in the cost of capital assets while routine repair and maintenance costs are expensed in the period incurred.

The Trust amortizes the cost of capital assets, net of salvage value, on a straight-line basis based on the estimated useful life of the assets, with the exception of regulated natural gas distribution assets, where amortization is calculated on a straight-line basis or over the contract term of a specific agreement at rates approved by the regulatory authorities.

Gas	
Extraction and transmission (E&T) assets	15–40 years
Field gathering and processing (FG&P) assets	15–25 years
Energy Services assets	19 years
Storage assets	20–50 years
Natural gas distribution assets	0.85–23.82 percent
Other assets	1–32 years
Power	
Assets under capital lease	10 years
Power generation assets	20–30 years
Corporate	
Other assets	1–5 years

Depletion of natural gas properties is provided using the unit of production method based upon estimated proved reserves before royalties.

Leases are classified as either capital or operating. Leases that transfer substantially all the benefits and risks of ownership of property to AltaGas are accounted for as capital leases. Assets under capital lease are accounted for as assets and are amortized on a straight-line basis over the lease term. The capital lease obligations reflect the present value of future lease payments. The finance element of the lease payments is charged to income over the term of the lease. Commitments to repay the principal amounts arising under capital lease obligations are included in current liabilities to the extent that the amount is repayable within one year; otherwise, the principal is included as a long-term debt.

Net additions to natural gas distribution assets at AUI and Heritage Gas are not depreciated until the year after they are brought into active service, as required by the respective regulatory authorities.

Energy Arrangements, Contracts, Relationships and Amortization

Energy arrangements, contracts and relationships are recorded at cost, which was fair value at the time of purchase, and are amortized on a straight-line basis over their term or estimated useful life.

Sundance B power purchase arrangements (PPAs)	19 years
Natural gas and power marketing contracts	18–49 months
Energy Services relationships	15 years
E&T contracts	10–20 years

AltaGas owns 50 percent of two Sundance B PPAs through its interest in the ASTC. ASTC is committed to purchasing all of the power from the two 353-MW capacity Sundance B generating units. The investment in the PPAs and the corresponding revenue and expenses thereunder are recorded on a proportionate basis. Acquisition of the Sundance B PPAs required a capital outlay. The Trust is obligated to make payments to the owners of the underlying generating units over the remaining terms of the PPAs to December 31, 2020. Such amounts are recorded as cost of sales as incurred. Revenue from the sale of the committed power is recorded based on target generator availability.

The natural gas and power marketing contracts are the rights and obligations to buy and sell fixed volumes of natural gas and power at contracted prices. Revenue and expenses are recorded when product is delivered.

Energy Services relationships were purchased along with substantially all of the assets and liabilities of iQ2 Power Corp., PremStar Energy Canada Ltd. (re-named AltaGas Energy Limited Partnership subsequent to acquisition), ECNG Canada Ltd. and Energistics Group Inc. and are recorded at fair value and amortized on a straight-line basis commencing with the expiration of the related short-term marketing contracts over the 15-year expected useful life of the relationships.

The E&T contracts were acquired through the acquisition of Taylor NGL Limited Partnership (Taylor) (note 3) and are recorded at fair value and amortized on a straight-line basis over the average expected life of the contracts.

All financial instruments, including derivatives, are included on the Consolidated Balance Sheets initially at fair value. The financial assets are classified as held-for-trading, held-to-maturity, loans and receivables, or available-for-sale. Financial liabilities are classified as held-for-trading or other financial liabilities. Subsequent measurement is determined by classification.

Held-for-trading financial assets and liabilities are entered into with the intention of generating a profit and consist of swaps, options, forwards and equity investments. These financial instruments are initially accounted for at their fair value, and changes to fair value are recorded in income. Held-to-maturity financial assets are accounted for at their amortized cost using the effective interest method. The Trust does not have any held-to-maturity financial instruments. Loans and receivables are accounted for at their amortized cost using the effective interest method. The available-for-sale classification includes non-derivative financial assets that are designated as available-for-sale or are not included in the other three classifications. Available-for-sale instruments are initially accounted for at their fair value, and changes to fair value are recorded through other comprehensive income. Investments in equity instruments that do not have a quoted market price in an active market are measured at cost. Income earned from these investments is included in other revenue.

Other financial liabilities not classified as held-for-trading are accounted for at their amortized cost, using the effective interest method.

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are not the same as those of a stand-alone derivative, and the total contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in income. All derivatives, other than those that meet the expected purchase, sale or usage requirements exception, are carried on the Consolidated Balance Sheets at fair value. The Trust used January 1, 2003 as the transition date for identifying embedded derivatives.

As part of its asset and liability management, the Trust uses derivatives to reduce its exposure to commodity price, interest rate and foreign exchange risk. The Trust designates certain derivatives as hedges and prepares documentation at the inception of the hedging contract. The Trust performs an assessment at inception and during the term of the contract to determine if the derivative used as a hedge is effective in offsetting the risks in the values or cash flows of the hedged item. All derivatives are initially recorded at fair value and adjusted to fair value at each reporting date.

The effective portion of changes in the fair value of cash flow hedges is recognized in other comprehensive income (OCI). Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income. Gains or losses from cash flow hedges that have been included in accumulated other comprehensive income are included in net income when the underlying transaction has occurred or is likely not to occur. The Trust has hedged certain future cash flows over a range of periods to a maximum of seven years.

Comprehensive Income and Equity

The Trust's financial statements include a Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income, which consists of earnings and the effective portion of changes in unrealized gains and losses related to available-for-sale assets and cash flow hedges. In addition, the Trust presents separately in its unitholders' equity note the changes for each of its components of unitholders' equity. Accumulated other comprehensive income and a one-time transition adjustment have been added to the Trust's unitholders' equity as a result of the implementation of this standard.

Long-Term Investments and Other Assets

Investments in entities in which AltaGas has the ability to exercise significant influence are accounted for by the equity method. Other long-term investments are recorded at cost and designated as available-for-sale or held-for-trading. Available-for-sale assets are initially accounted for at their fair value with changes to fair value recorded through OCI. Investments in equity instruments that do not have a quoted market price in an active market will be measured at cost. Held-for-trading assets are initially accounted for at fair value with changes in fair value recorded in other revenue.

Development Costs

The Trust expenses development costs as incurred unless such development costs meet certain criteria related to technical, market, regulatory and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria are still met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

Asset Retirement Obligations

The Trust recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to operating and administrative expense in the Consolidated Statements of Comprehensive Income and Accumulated Other Comprehensive Income.

No asset retirement obligations have been recorded for certain transmission and distribution assets due to their indeterminate life.

Revenue Recognition

In the Gas Segment, the extraction and transmission, field gathering and processing and Energy Services business recognize revenue at the time the product or service is delivered. The natural gas distribution business recognizes revenue when the product or service is delivered on the basis of regular meter readings or estimates of usage and is consistent with the underlying rate-setting mechanism mandated by the applicable regulating authority.

The Power Segment recognizes revenue based on target generator availability in accordance with the Sundance B PPAs and at the time the product or service is delivered for all other power generation.

Realized gains and losses from risk management activities related to commodity prices are recognized in the related segment revenues when the sale occurs or when the underlying financial asset or financial liability is removed from the Consolidated Balance Sheets. Unrealized gains and losses in respect of fair value changes to the Trust's risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the reporting period in the Corporate Segment.

Transaction Costs Related to Financial Instruments

Transaction costs related to the acquisition of held-for-trading financial assets and liabilities are expensed as incurred. For financial instruments classified as other than held-for-trading, transaction costs attributable to the acquisition or issue of the financial asset or liability are added to the initial carrying amount of the financial instrument and recognized in earnings using the effective interest method.

Monetary assets and liabilities denominated in a foreign currency are translated at the exchange rate in effect at the balance sheet date. Non-monetary assets and liabilities are translated at the exchange rate in effect at the transaction date. Revenues and expenses are converted at the average exchange rate applicable to the period.

AltaGas uses the settlement date for transactions. Any difference in value between the trade and settlement date for third-party transactions will be recognized on the balance sheet and in net income or in OCI as appropriate.

The Trust uses the effective interest method to calculate the amortized cost of a financial asset or liability and to allocate the interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts the estimated cash flows associated with the instrument over the expected life of the financial instrument, or where appropriate a shorter period, to the net carrying amount of the financial asset or liability.

The Trust follows the fair value method of accounting for Trust unit options granted during the year. Unit options are valued at the date of the grant and recognized as compensation expense over the vesting period of the options. Consideration received by the Trust on exercise of the option rights is credited to unitholders' capital.

AltaGas has a Mid-Term Incentive Plan in which participants receive phantom units requiring settlement of cash payments. During the graded vesting period, compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the vested phantom units is recognized in the period the change occurs.

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The current service cost is the sum of the individual current service costs, and the accrued benefit obligation is the sum of the accrued liabilities for all participants.

For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The cumulative net actuarial gain or loss at the beginning of the year in excess of 10 percent of the greater of the accrued benefit obligation and the fair value of plan assets is amortized on a straight-line basis over the average remaining service life of the active employees. The average remaining service period of the active members covered by the defined benefit pension plans and post-retirement benefit plans is 14.8 years and 10.1 years, respectively. Transitional obligations are being amortized on a straight-line basis over the remaining service life of active employees. Past service costs resulting from plan amendments are amortized on a straight-line basis over the average remaining service life of active employees for the respective plan.

The Trust is a taxable entity under the Income Tax Act (Canada), and its income that is not paid or payable to the unitholders is taxable in a particular taxation year. Prior to 2007 the Trust allocated all of its Canadian taxable income to the unitholders in accordance with its Trust indenture and met the requirements of the Income Tax Act (Canada) applicable to the Trust. Accordingly, no provision for Canadian income tax expense was made for the Trust.

On June 22, 2007 the Specified Investment Flow-through (SIFT) tax received royal assent, creating a new tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. On December 14, 2007 reduced tax rates were enacted and are to be applied to distributions at the tax rates of 29.5 percent and 28.0 percent effective January 1, 2011 and 2012, respectively.

Based on the amount of the Trust's temporary differences that were anticipated to reverse after January 1, 2011, the Trust had recorded a SIFT future income tax expense and future income tax liability for the year ended December 31, 2007. This non-cash expense had no immediate impact on cash flows. Temporary differences occur when the book carrying value of AltaGas' assets and liabilities for accounting purposes differs from the amounts attributed to these same assets and liabilities for tax purposes. A tax rate of nil was applied to any temporary differences reversing before 2011.

In 2008 the partnership in which the temporary differences for SIFT tax purposes resided was moved under an operating subsidiary, with the result the SIFT future tax liability was replaced by a future tax liability at corporate tax rates.

The anticipated amount and timing of reversals of temporary differences will be dependent on the Trust's actual results, distributions and actual acquisition and disposition of assets and liabilities and restructuring within the Trust. As a result, a change in estimates or assumptions could materially affect the estimate of the future tax liability.

Income taxes are calculated in the subsidiary companies of the Trust using the liability method of tax accounting. Under this method, future income tax assets and liabilities are determined based on differences between the book carrying value and the tax bases of assets and liabilities and are measured using the substantively enacted tax rates and laws that are anticipated to be in effect in the periods in which the differences are expected to be settled or realized. GAAP requires these future income tax liabilities to be recognized in the Consolidated Financial Statements.

Related Party Transactions

Transactions with related parties that are conducted in the normal course of operations and non-routine transactions have been recorded at the exchange amount.

Per-Unit Information

Basic net income per unit is calculated on the basis of the weighted average number of trust and exchangeable units outstanding during the period. Diluted net income per unit is calculated as if the proceeds obtained upon exercise of options were used to purchase units at the average market price during the period plus the trust units issuable on conversion of outstanding convertible debentures and warrants. Diluted net income is increased by the interest on the convertible debentures and decreased by the accretion on the convertible debentures. As of September 16, 2009 the Trust redeemed any outstanding convertible debentures.

Use of Estimates and Measurement Uncertainty

The preparation of consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments when matters are inherently uncertain include but are not limited to amortization, asset impairment, litigation, environmental and asset retirement obligations, financial instruments, pension plans and other post-retirement benefits, unit-based compensation, income taxes and regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which AltaGas' subsidiaries or affiliates operate, which often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty and may impact the Consolidated Financial Statements of future periods.

Warrants

Warrants are recorded at fair value, deemed to be the gross proceeds upon issue and are included as part of unitholders' equity.

Emission Credits

Emission credits purchased or generated internally are recorded at fair value and included in other current assets. Cost is deemed to be the fair value as no active market currently exists for emission credits.

UTURE ACCOUNTING CHANGES

ection 1582 "Business Combinations

This section applies to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011. The new CICA Handbook Section 1582 will replace Section 1581 "Business Combinations", establishing standards for the accounting for a business combination that will more closely resemble those under International Financial Reporting Standards (IFRS). Earlier adoption of this section is permitted. The section is not expected to have a material impact on the Consolidated Financial Statements.

Section 1601 "Consolidated Financial Statements" and Section 1602 "Non-Controlling Interests"

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2011, the new CICA Handbook Sections 1601 and 1602 will replace Section 1600 "Consolidated Financial Statements". These sections establish standards for the preparation of consolidated financial statements and accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Earlier adoption of this section is permitted as of January 1, 2010 for the Trust. Management has not fully determined the impact of adopting this standard.

ational Financial Reporting Standards (IFRS)

Canadian publicly traded companies will be required to prepare their financial statements in accordance with IFRS as issued by the International Accounting Standards Board, for the financial years beginning on or after January 1, 2011. Effective January 1, 2011, AltaGas will adopt IFRS as the basis for preparing its Consolidated Financial Statements. Financial results for the quarter ended March 31, 2011 shall be prepared on an IFRS basis, with comparative data on an IFRS basis, including an opening balance sheet, as at January 1, 2010. Management has not fully determined the financial impact of adopting IFRS on its financial statements; however, it should be noted that the current financial statements may be significantly different if presented in accordance with IFRS.

SINESS ACQUISITIONS

AltaGas Utility Group Inc

On October 8, 2009 AltaGas Holdings No. 3 Inc. (AltaGas Holdings #3), an indirect wholly owned subsidiary of AltaGas, acquired all of the outstanding common shares of Utility Group not already owned by AltaGas and its affiliates.

Utility Group was a publicly traded company holding interests in AUI, Heritage Gas and Inuvik Gas. Utility Group also holds a 33.3335 percent interest in the Ikhil Joint Venture (Ikhil), which produces and supplies natural gas in Inuvik, Northwest Territories.

AltaGas paid Utility Group shareholders $10.50 per common share in cash. The aggregate purchase price was $80.2 million, including $75.2 million of cash for the remaining 81.7 percent of Utility Group and $5.0 million in transaction costs.

Until the date of acquisition, AltaGas accounted for its investment in Utility Group using the equity method. As a result, the Trust's portion of income earned by Utility Group was recorded as other revenue in the Corporate Segment. As of October 8, 2009, the operating results of Utility Group are consolidated with the results of the Trust within the Gas Segment.

AltaGas drew on its available credit facility to finance the cash consideration of $75.2 million for the Utility Group acquisition.

Heritage Gas Limited

On November 18, 2009 AltaGas acquired all of the Heritage Gas common shares and shareholder loans not already owned. Heritage Gas operates a full regulation-class natural gas distribution franchise in Nova Scotia.

AltaGas paid approximately $109.8 million for the remaining 75.1 percent in Heritage Gas. The aggregate purchase price was $111.0 million, including $109.8 million of cash for all of the common shares and shareholder loans not previously owned and $1.2 million in transaction costs.

Until the date of acquisition, AltaGas accounted for its investment in Heritage Gas using the proportional accounting method.

Purchase Price Allocation

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed on October 8, 2009 and November 18, 2009 for Utility Group and Heritage Gas, respectively. Any final adjustments may significantly change the allocation of the purchase price and could affect the fair value assigned to assets and liabilities. The preliminary allocation of the purchase price is as follows:

	Utility Group	Heritage Gas	Total
Cash consideration	$ 75,199	$ 109,828	185,027
Estimated transaction costs	5,000	1,200	6,200
Total consideration			191,227

	Utility Group	Heritage Gas	Total
Purchase price allocation			
Assets acquired			
Current assets	$ 16,743	$ 5,377	
Capital assets	149,371	74,808	
Regulatory assets	16,633	34,509	
Goodwill (note 7)	44,143	13,895	
Long-term investments and other assets	3,267	–	358,746
Less liabilities assumed			
Current liabilities	23,078	8,214	
Long-term debt	101,511	–	
Regulatory liabilities	13,587	–	
Asset retirement obligations	96	–	
Future income taxes	9,113	9,347	
Future employee obligations	2,573	–	167,519
			191,227

In accordance with CICA Handbook Section 1600 "Consolidated Financial Statements", AltaGas accounted for the Utility Group acquisition as a step-by-step purchase resulting from the Trust's original equity accounted investment in Utility Group. Accordingly, the $12.3 million investment was proportionately allocated to identifiable assets and liabilities of Utility Group.

2008

Acquisition of Taylor NGL Limited Partnership

On January 10, 2008 AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1) acquired all of the outstanding limited partnership units of Taylor (other than the Taylor units already owned by AltaGas and its affiliates). Taylor participated in the energy business through ownership of NGL extraction plants, natural gas processing assets and two NGL pipelines. It also had an interest in a 7-MW run-of-river hydroelectric generation plant.

AltaGas offered Taylor unitholders $11.20 in cash or 0.42 units of AltaGas per unit of Taylor, subject to maximum aggregate limits of $245.0 million in cash and 8.0 million Trust units, including up to approximately 1.9 million exchangeable units. Prior to closing the acquisition, $27.9 million of Taylor convertible debentures were redeemed, increasing Taylor units outstanding by 2.7 million. AltaGas paid $256.3 million of cash and 7.7 million Trust units (including 0.2 million exchangeable units) valued at $198.9 million for all the outstanding units not previously owned by AltaGas and $5.9 million in transaction costs. The value of the Trust units issued was determined based on the weighted average market price between two days preceding and two days subsequent to November 11, 2007, the date the offer had been agreed upon and announced.

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed at January 10, 2008. The allocation of the purchase price is as follows:

Total consideration for 100% of Taylor		
Cost of 8.9% investment in Taylor originally owned by AltaGas		$ 23,156
Purchase price for the remaining 91.1% of Taylor units		
Cash consideration	$ 256,281	
Units	198,861	
Estimated transaction costs	5,884	
Equity portion of Taylor convertible debentures	2,127	463,153
Total consideration		$ 486,309

Purchase price allocation for 100% of Taylor		
Assets acquired		
Current assets	$ 30,584	
Capital assets	592,030	
Energy arrangements, contracts and relationships	53,100	
Goodwill (note 7)	125,680	
Long-term investments and other assets	4,640	806,034
Less liabilities assumed		
Current liabilities	27,549	
Long-term debt	110,423	
Convertible debentures	22,171	
Asset retirement obligations	18,741	
Future income taxes	135,320	
Future employee obligations	2,542	
Risk management	2,979	319,725
		$ 486,309

At the date of acquisition, AltaGas accounted for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available-for-sale and was measured at fair value, with the changes in fair value recorded in OCI. As of January 10, 2008 Taylor was included in AltaGas' Consolidated Financial Statements.

AltaGas drew on its available credit facility to finance the cash consideration of $256.3 million for the Taylor acquisition.

[illegible]

On July 31, 2008 AltaGas acquired NovaGreen Power Inc. (re-named AltaGas Renewable Energy Inc.) a wholly owned subsidiary of NovaGold Resources Inc., for $35 million on closing, with an additional $3.75 million on completion of certain conditions. AltaGas Renewable Energy Inc. is developing the Forrest Kerr run-of-river hydroelectric project in northwest B.C., which is expected to have capacity of 195 MW. AltaGas Renewable Energy Inc. is also pursuing three other development projects, all within the same region as Forrest Kerr, with additional potential combined run-of-river hydroelectric capacity of approximately 130 MW.

On August 15, 2008 AltaGas acquired GreenWing Energy Management Ltd.'s 45 percent interest in GreenWing Energy Development Limited Partnership (re-named AltaGas Renewable Energy Limited Partnership) for $12.3 million. As a result, the Trust now owns 100 percent of AltaGas Renewable Energy Limited Partnership. The portfolio of wind assets includes 650 MW in mature-stage development and 850 MW in early-stage development.

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULAT

AltaGas accounts for certain transactions in accordance with applicable regulations enforced by the AUC and NSUARB, which may be different in the absence of rate regulations. This results in the creation of regulatory assets and liabilities.

When the AUC or NSUARB issues a decision affecting the financial statements, the effects of the decision are recorded in the period in which the decision is received. However, if in management's judgment a reasonable estimate can be made regarding the impact a pending decision will have on the current year's financial statements, an estimate will be recorded in the current year for the expected impact.

Return on Rate Base

A generic cost of capital proceeding in Alberta during 2009 resulted in an AUC decision setting the return on equity for 2009 and 2010 at 9 percent. The AUC 2009 generic cost of capital decision further set AUI's regulated capital structure at 57 percent debt and 43 percent equity.

Heritage Gas' regulated capital structure is set at 55 percent debt and 45 percent equity with a return on equity of 13 percent. The NSUARB has approved this structure and return until December 31, 2011.

Regulatory Process – Delivery Tariff:

AUI's and Heritage Gas' delivery tariffs are designed to recover AUI's and Heritage Gas' approved cost-of-service and an approved return on equity. Tariffs are determined through a two-phase General Rate or Tariff Application (GTA). Phase 1 establishes the revenue requirement and Phase 2 sets the rates to be charged to various customer classes.

AUI seeks approval of its revenue requirement through a negotiated settlement process with interested parties or through an administrative hearing before the AUC. The AUC monitors the negotiated settlement process, and AUC approval is required for any settlement AUI reaches with interested parties. Factors affecting AUI's revenue requirement include forecasts for rate base, distribution and other revenue, operating costs, depreciation, financing costs, income taxes and return on rate base.

Heritage Gas uses an administrative hearing before the NSUARB for the two phases of the regulatory process.

Although the approved revenue requirement and subsequent approved rates are based on forecasts and actual results can differ from these forecasts, no adjustment is made to either the revenue requirement or rates for actual results varying from forecast. Once the rates are approved for a period, all risks and rewards from differences in actual versus forecast energy units delivered, capital expenditures, number of service sites billed, operating costs, debt servicing costs and taxes are borne by the unitholders. Actual results achieved can therefore differ from allowed returns.

Regulatory Process – Gas Cost Recovery Rate and Third-Party Transporta

The Gas Cost Recovery Rate (GCRR) is charged to consumers for gas supply and is designed to allow AUI and Heritage Gas to recover the market-determined price paid for natural gas without any markup. The AUC and NSUARB have established a framework for AUI and Heritage Gas to file their costs monthly with the AUC and NSUARB, respectively. The AUC reviews AUI's GCRR applications to ensure that only the actual cost of gas is passed on to customers. Once verified by the AUC, interested parties have 30 days to file any objections to the rate. The NSUARB has established that it does not have jurisdiction over setting the GCRR and therefore Heritage Gas advises the NSUARB of the new price for the following month.

The Third-Party Transportation Rate (TPTR) is designed to allow AUI to recover third-party gas transportation service costs without any markup and is administered in an equivalent manner to GCRR. The TPTR applies to customers buying retail gas supply, which is the non-regulated gas supplied by competitive retailers, as well as customers buying default gas supply, since third-party transportation is required by all customers.

Cost of Natural Gas Sales

The cost of natural gas sales included in customer rates is based on the forecast cost of natural gas. As described in the GCRR process above, variances between forecast cost and actual costs of natural gas are deferred for refund to or collection from customers through adjustments to future rates. For both AUI and Heritage Gas, such adjustments generally occur in the following month.

Cost of natural gas sales for Inuvik Gas is based on market rates and there is no cost pass-through mechanism.

Regulatory Assets

Deferred Charges

Certain charges connected with costs of regulation are recorded at cost, deferred and amortized as approved by the regulator. The recovery or settlement period, or likelihood of recovery or settlement, of deferred charges is affected by the ultimate treatment by the regulator in the rate-setting process. There is risk and uncertainty that the regulator may not allow full recovery of recorded regulated assets.

Revenue Deficiency Account

Heritage Gas has approval from the NSUARB to use a Revenue Deficiency Account (RDA). The RDA changes are based on the difference between the actual revenue billed and the revenue required to earn the rates of return approved by the NSUARB. AUI accrues revenue equal to the difference between the revenue requirement expected to be received under its proposed GTA and the sales revenues at current approved rates. When the AUC issues a decision regarding the GTA, AUI bills revenue based on the approved revenue requirement and the revenue forecast to be collected at current approved rates and collects the revenue by way of a deficiency rate rider. The AUI accrual is included in accounts receivable.

AUI accrues revenue associated with the difference between the accrued costs and the funded costs of other retirement benefits. This revenue is recovered from customers in future periods in a manner that is consistent with the underlying rate-setting mechanism as mandated by the regulator.

For entities not subject to rate regulation, GAAP does not provide for the accrual of a revenue deficiency. Revenue would be recognized based on services provided to customers during the period.

Regulatory assets and liabilities recognized in the Consolidated Balance Sheet as at December 31, 2009 are as follows:

Regulatory assets – current		
Deferred cost of gas		2,567
	$	2,567
Regulatory assets – non-current		
Deferred charges		474
Future recovery of other retirement benefits		1,416
Deferred depreciation		2,546
Deferred future taxes		22,583
Revenue deficiency account		33,866
	$	60,885
Regulatory liabilities– current		
Deferred property taxes		70
Deferred cost of gas		72
Deferred regulatory costs		1,261
	$	1,403
Regulatory liabilities – non-current		
Future removal and site restoration costs		16,610
	$	16,610

AUI incurred costs to meet CEO/CFO certification requirements as mandated by the Canadian Securities Administrators. For regulatory purposes, differences between forecast and actual costs are held as a regulatory asset until the regulator rules on their final disposition. As directly by the AUC, AUI expensed the remaining deferred charges during the year through operating and administrative expenses. In the absence of regulatory accounting, GAAP would require that actual CEO/CFO certification costs be recognized as an expense when incurred and operating income would have been $0.4 million higher in 2009.

For rate-setting purposes at Heritage Gas and AUI, differences between forecast and actual costs of regulatory proceedings are held as a regulatory asset or liability until the regulator rules on their final disposition. Heritage incurred costs related to regulatory proceedings in 2004, 2006 and 2007. These costs are being amortized on a straight-line basis over a five-year period as approved by the NSUARB. Regulatory costs at AUI are included in 2009 allowed rates on a interim basis using forecast costs. AUI intends to seek and expects to receive the regulator's approval for refund of the year-end 2009 deferred regulatory costs in future rate proceedings. AltaGas expensed $0.3 million deferred charges in 2009 through operating and administrative costs. In the absence of regulatory accounting, GAAP would require that actual regulatory costs be recognized as an expense when incurred, and operating income would have been $0.3 million higher in 2009.

Natural gas and transportation costs are included in the approved tariff on a monthly forecast basis. For rate-setting purposes differences between forecast and actual costs in the month are held for collection or refund in the following months. AltaGas recognizes the cost variances as a regulatory asset or liability based on the expectation that amounts held from one month to the next for regulatory purposes will be approved for collection from or refund to customers in future months. AltaGas expects to recover the outstanding deferred costs in the first quarter of the following year. In the absence of regulatory accounting, GAAP would require that actual costs be recognized as an expense when incurred, and operating results would have been $2.1 million lower in 2009.

Future income taxes expected to be included in future recoveries from customers are deferred in accordance with CICA Handbook Section 3465. In the absence of rate regulation, GAAP would require that future income taxes be recognized in income when incurred and net income would have been $1.5 million lower in 2009.

Property taxes are included in allowed rates on an annual forecast basis. For regulatory purposes, differences between forecast and actual costs in the year are held for collection or refund in the following month. AUI recognizes the cost variances as a regulatory asset or liability based on the expectation that amounts held from one year to the next for regulatory purposes will be approved for collection from or refund to customers in future years. AltaGas expects to refund the December 31, 2009 outstanding deferred costs in 2010. In the absence of regulatory accounting, GAAP would require that actual costs be recognized as an expense when incurred.

Other retirement benefits are accounted for on an accrual basis in accordance with CICA Handbook Section 3461. For regulatory purposes, these other retirement benefit costs are recoverable from customers based on the funding of the costs. The revenue associated with the difference between the accrued costs and the funded costs is accrued and is expected to be recovered from customers in future periods. In the absence of regulatory accounting, GAAP would require that accrued revenue be recognized in the period earned, and operating income would have been $0.1 million lower in 2009.

Pursuant to the NSUARB decision dated February 12, 2009, Heritage Gas was ordered to suspend amortization for regulatory purposes for the 2009–2011 period. As a result of this order, Heritage Gas has set up a regulatory asset equal to the amortization required under GAAP. The effect of this decision for the year ended December 31, 2009 was to record a deferred regulatory revenue accrual of $2.5 million and deferred regulatory asset of $2.5 million. This regulatory deferral amount is expected to be recovered on the same basis as the amended amortization charge over the remaining useful life of related assets commencing in 2012.

Future removal and site restoration costs are included in revenue as allowed by the regulator. AUI recognizes the variance between amounts collected and future removal and site restoration costs incurred as a regulatory asset or liability based on the expectation that amounts held for regulatory purposes will be approved for collection from or refund to customers in future periods. In the absence of rate regulation, GAAP would require that the variance between the amounts collected and incurred be recognized as revenue in the period of collection, and income would have been $0.1 million lower in 2009.

The RDA at December 31, 2009 was $33.9 million. The effect of the RDA accumulation was to increase 2009 revenue by $0.9 million. In the absence of regulatory accounting, GAAP would require that the revenue deficiency account would not be recognized and would have reduced operating income by $0.9 million in 2009.

	2009			2008		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Gas						
E&T assets	$ 896,753	$ (97,998)	$ 798,755	$ 871,042	$ (70,590)	$ 800,452
FG&P assets	629,284	(202,791)	426,493	619,465	(174,797)	444,668
Energy services assets	1,555	(1,343)	212	1,555	(1,173)	382
Storage assets	23,423	(284)	23,139	9,053	–	9,053
NGD assets	271,464	(1,420)	270,044	–	–	–
Other assets	8,303	(5,339)	2,964	7,791	(4,003)	3,788
Power						
Capital lease (note 10)	13,798	(7,358)	6,440	13,798	(6,119)	7,679
Power generation assets	323,118	(1,081)	322,037	158,881	(72)	158,809
Other assets	330	–	330	–	–	–
Corporate						
Other assets	23,270	(16,589)	6,681	25,919	(14,064)	11,855
	[illegible]	[illegible]	[illegible]	$ 1,707,504	$ (270,818)	$ 1,436,686

Interest capitalized on long-term capital construction projects for the year ended December 31, 2009 was $7.1 million (2008 – $3.2 million). At December 31, 2009 the Trust had spent approximately $326.8 million (2008 – $188.1 million) on capital projects under construction that were not yet subject to amortization.

Net additions to natural gas distribution assets at AUI and Heritage Gas are not amortized until the year after they are brought into active service, as required by the respective regulating authorities. Natural gas distribution assets not subject to amortization were $18.7 million as at December 31, 2009 (December 31, 2008 – nil).

	2009			2008		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Energy services and E&T arrangements and contracts	$ 168,171	$ (54,799)	$ 113,372	$ 168,171	$ (46,228)	$ 121,943
Energy services relationships	20,892	(5,315)	15,577	20,892	(3,922)	16,970
	[illegible]	[illegible]	[illegible]	$ 189,063	$ (50,150)	$ 138,913

The amortization of the energy services relationships began in 2006, upon expiration of the corresponding short-term marketing contracts.

	2009	2008
Balance, beginning of year	$ 143,840	$ 18,260
Acquisition (note 3)	58,038	125,680
Goodwill impairment	(150)	(100)
Balance, end of year	$ 201,728	$ 143,840

Through its annual goodwill impairment testing in 2009, AltaGas determined that the fair value of an investment was less than the book value and reduced the carrying value by $0.2 million (December 31, 2008 – $0.1 million).

8. LONG-TERM INVESTMENTS

		2008 [1]
Equity accounted investments in publicly traded entities	$ –	$ 12,660
Investments in publicly traded entities	24.332	–
Equity accounted investments in private entities [2]	3,999	4,366
Warrants	–	286
Accrued pension asset	1.361	–
Other	795	432
	[illegible]	$ 17,744

1 Excludes the purchase of Taylor and power projects under development (note 3).

2 The Trust accounts for its investment in Boston Bar Limited Partnership, which has run-of-river hydroelectric operations, using the equity method.

At December 31, 2009 the quoted market value of the holdings of publicly traded entities was $24.3 million (December 31, 2008 – $7.7 million).

Prior to the October 8, 2009 acquisition of the remaining shares of Utility Group, AltaGas accounted for its investment in Utility Group using the equity method. As a result, the Trust's portion of income earned by the Utility Group was recorded as other revenue in the Corporate Segment. As of October 8, 2009, the operating results of the Utility Group are consolidated with the results of the Trust within the Gas Segment.

9. SHORT-TE[illegible]

		2008
Bank indebtedness	$ 4,950	$ 4,493
$50 million demand operating facility	–	–
$20 million demand operating facility	2.444	–
$15 million demand operating facility	6,960	–
$1.0 million demand operating facility	272	–
	[illegible]	$ 4,493

Revolving Operating Credit Facili[illegible]

At December 31, 2009 the Trust held a $50.0 million (December 31, 2008 – $50.0 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee.

On October 8, 2009 the Trust acquired a $20 million unsecured uncommitted demand operating credit facility with a Canadian chartered bank through the acquisition of Utility Group (note 3). Draws on the facility can be by way of prime rate loans, U.S. base rate loans, letters of credit, bankers' acceptances and LIBOR loans. Letters of credit outstanding at December 31, 2009 were $1.0 million.

AltaGas acquired a further $15 million unsecured uncommitted demand operating credit facility with a Canadian chartered bank through the acquisition of Utility Group (note 3). Draws on the facility can be by way of prime rate loans, letters of credit or bankers' acceptance equivalent loans. Letters of credit outstanding at December 31, 2009 were $1.4 million.

On November 18, 2009 the Trust acquired a $1.0 million demand credit facility from a Canadian chartered bank through the acquisition of Heritage Gas (note 3). It is secured by a general security agreement on the property of Heritage Gas and bears interest at prime plus one percent. Draws on the facility are by way of loans bearing interest at the bank's prime rate or by way of letters of credit or letters of guarantee for a fee.

Bank indebtedness bears interest at the lender's prime rate. The prime lending rate at December 31, 2009 was 2.25 percent (December 31, 2008 – 3.50 percent).

	2009	2008
Credit facilities	$ 490,518	$ 353,000
Medium-term notes	500,000	200,000
Loan from Province of Nova Scotia	4,272	–
Capital lease obligations	7,484	8,800
Other long-term debt	1,049	1,282
Unamortized deferred financing	(3,209)	(2,307)
	1,000,114	560,775
Less current portion	591,944	1,363
	$ 408,170	$ 559,412

At December 31, 2009 the Trust held a $375.0 million (December 31, 2008 – $375.0 million) unsecured extendible revolving three-year credit facility with a syndicate of Canadian chartered banks. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. On September 30, 2007 AltaGas negotiated the extension of the maturity of this facility to September 30, 2010.

On March 10, 2009 the Trust closed a $250.0 million unsecured 18-month credit facility with a syndicate of Canadian chartered banks that matures on August 13, 2010, replacing the credit facility that was due to mature on September 28, 2009. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances. Borrowings on the facility bear fees and interest rates relevant to the nature of the draw. On April 29, 2009 the Trust issued $200 million of senior unsecured medium-term notes (MTNs). On June 29, 2009 AltaGas issued $100 million of senior unsecured MTNs. In accordance with the terms of the $250 million credit facility, $100 million of the MTN proceeds were used to repay and reduce the facility from $250 million to $150 million on July 9, 2009.

On October 8, 2009 the Trust acquired a $130 million unsecured extendible revolving credit facility through the acquisition of Utility Group (note 3) with a syndicate of Canadian chartered banks with a maturity date of November 17, 2010. Borrowings on the facility can be by way of prime rate loans, U.S. Bank rate, letters of credit, LIBOR or bankers' acceptance equivalent loans.

At December 31, 2009 the Trust had drawn $490.5 million (December 31, 2008 – $353.0 million) against the facilities. The average rate on the Trust's bankers' acceptances at December 31, 2009 was 1.2 percent (December 31, 2008 – 3.1 percent).

On August 30, 2005 $100.0 million of 4.41 percent senior unsecured MTNs were issued. The notes mature on September 1, 2010, with interest payable semi-annually.

On January 19, 2007 AltaGas issued $100.0 million of 5.07 percent senior unsecured MTNs. The notes carry a coupon rate of 5.07 percent and mature on January 19, 2012.

On April 29, 2009 AltaGas issued $200 million of 7.42 percent senior unsecured MTNs. The notes carry a coupon rate of 7.42 percent and mature on April 29, 2014.

On June 29, 2009 AltaGas issued $100 million of 6.94 percent senior unsecured MTNs. The notes carry a coupon rate of 6.94 percent and mature on June 29, 2016.

Loan from Province of No

On October 8, 2009 AltaGas acquired a loan from the Province of Nova Scotia through the acquisitions of Utility Group and Heritage Gas (note 3). Heritage Gas, an indirectly wholly owned subsidiary of Utility Group, received $7.6 million from the Province of Nova Scotia in 2005, $2.0 million of which was forgiven on January 1, 2007. The loan is non-interest-bearing until certain revenue targets are achieved, at which time interest will be charged prospectively at 6 percent. On or before July 31, 2011, AltaGas must elect to repay the loan in full on July 1, 2014 or in five equal instalments beginning July 31, 2012. AltaGas may also elect to fully repay the loan at any time with no penalty. The loan is recorded at its amortized cost of $4.3 million. Interest expense is recorded at the effective interest rate of 6 percent. The face value of the loan is $5.6 million as at December 31, 2009.

Capital Lease Obligation

On September 1, 2004 the Trust entered into a 10-year capital lease for 25 MW of gas-fired power-peaking capacity with an option to extend the term for an additional 15 years. The lease has payment commitments as follows, excluding the extended term option:

2010	$	1,878
2011		1,878
2012		1,878
2013		1,878
2014		1,254
		8,766
Less imputed interest at 6.85%		1,282
Present value of minimum lease payments		7,484
Less current portion		1,408
	$	6,076

Interest expense on capital leases was $0.6 million in 2009 (2008 – $0.6 million).

Letter of Credit Facil

At December 31, 2009 the Trust held a $75.0 million (December 31, 2008 – $75.0 million) unsecured three-year extendible revolving-term letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made. At December 31, 2009 the Trust had letters of credit of $46.7 million (December 31, 2008 – $68.1 million) outstanding against the extendible revolving-term letter of credit facility.

11. CONVERTIBLE DEBENTURES

On September 16, 2009 the Trust redeemed $16.6 million of outstanding convertible debentures at an amount of $1,000.96 for each $1,000.00 principal amount. The redemption amount is equal to the principal plus all accrued and unpaid interest thereon.

The Trust recognized a gain on redemption of convertible debentures of $0.1 million as other revenue and applied $1.6 million to contributed surplus related to the equity portion of the convertible debentures.

		2009		2008
Balance, beginning of year	$	41,708	$	18,811
Obligations assumed under acquisition (note 3)		95		18,741
New obligations		742		–
Obligations settled		(384)		(744)
Obligations disposed		–		(219)
Revision in estimated cash flow		(3,528)		2,817
Accretion expense		3,138		2,302
Balance, end of year	$	41,771	$	41,708

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations at December 31, 2009 was $278.2 million (December 31, 2008 – $244.3 million). The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 5.6 and 8.5 percent and are expected to be incurred between 2016 and 2072. No assets have been legally restricted for settlement of the estimated liability.

The Trust has recorded a future income tax expense of $0.2 million for the year ended December 31, 2009 (2008 – recovery of $3.9 million) and an increase in future income tax liability of $17.3 million for the year ended December 31, 2009 (December 31, 2008 – $5.3 million).

Payments received by the Trust in the form of interest, distributions or other income from its subsidiaries are taxable income to the Trust. The Trust is entitled to deduct, for income tax purposes, its costs and its distributions to unitholders. Since it distributes all of its income to unitholders, the Trust is not expected to be liable for income taxes currently.

On June 22, 2007 the Specified Investment Flow-through (SIFT) tax received royal assent, creating a new tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. Based on the amount of the Trust's temporary differences that were anticipated to reverse after January 1, 2011, the Trust recorded a future income tax expense of $5.4 million (including $0.1 million expense in respect of financial instruments) and a future income tax liability in the same amount for the year ended December 31, 2007. This non-cash expense related to temporary differences between the accounting and tax basis of AltaGas' assets and liabilities held in partnerships and had no immediate impact on cash flows. A tax rate of nil was applied to any temporary differences reversing before 2011.

In 2008 the partnership in which the temporary differences resided was moved under an operating subsidiary, resulting in the Trust recording a SIFT future tax expense of nil at December 31, 2008 and the SIFT future tax liability being replaced by a future tax liability at corporate tax rates. In 2009 $18.5 million of future income tax liabilities was assumed as a result of the Utility Group acquisition (note 3).

Incorporated operating subsidiaries of the Trust are subject to tax in the same manner as any other corporation. Operating subsidiaries are generally not expected to pay significant taxes either currently or in the foreseeable future under existing tax legislation.

Consolidated Tax Position

The tax provision recorded in the Consolidated Financial Statements differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rates to income before tax as follows:

Years ended December 31		2009		2008
Income before taxes – consolidated	$	142,477	$	161,969
Financial instruments – net		(3,697)		(10,986)
Income before financial instruments and taxes		138,780		150,983
Income from AltaGas Income Trust distributed to unitholders		(135,119)		(134,849)
Income before income taxes – operating subsidiaries		3,661		16,134
Statutory income tax rate (%)		29.00		29.50
Expected taxes at statutory rates		1,062		4,760
Add (deduct) the tax effect of:				
Financial instruments		187		3,357
Rate reductions applied to future income tax liabilities		262		(11,347)
Permanent differences between accounting and tax basis of assets and liabilities		988		373
Non-taxable portion of capital gains on disposition of assets and investments		(1,798)		–
Other		(436)		1,255
Future income tax on regulated assets		[illegible]		–
Prior year adjustment		[illegible]		–
Income tax provision (recovery)				
Current		981		2,328
Future		187		(3,930)
	[illegible]	1,168	$	(1,602)
Effective income tax rate (%)		0.82		(0.99)

The amount shown on the Consolidated Balance Sheets as future income tax liabilities represents the net differences between the tax basis and book carrying values on the Trust's balance sheets at substantively enacted tax rates.

As at December 31, future income taxes were composed of the following:

December 31		2009		2008
Capital assets	$	206,742	$	162,680
Regulatory assets		18,196		–
Deferred debt charges		(7)		(60)
Unit issue costs		(40)		(679)
Partnerships		10,494		37,010
Deferred compensation		(4,942)		(3,890)
Financial instruments		10,711		16,260
Non-capital losses		(12,971)		–
Other		413		(65)
	[illegible]	[illegible]596	$	211,256

The Trust's objective for managing capital is to maintain its investment-grade credit ratings and allow the Trust to maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. The Trust considers unitholders' equity (including accumulated other comprehensive income), short-term and long-term debt (including current portion) less cash and cash equivalents to be part of its capital structure. The Trust's overall strategy remains unchanged from 2008.

The use of debt or equity funding is based on AltaGas' capital structure, which is determined by considering the norms and risks associated with each of its business segments. AltaGas' target debt-to-total-capitalization ratio was 40 to 45 percent until third quarter 2009. Subsequent to the acquisition of Utility Group (note 3), the Trust increased its target debt-to-total-capitalization ratio to 45 to 50 percent. The increase is the result of the addition of natural gas distribution assets to the Trust's portfolio of energy infrastructure assets. The Trust's debt-to-total-capitalization ratio as at December 31, 2009 was 49.2 percent (December 31, 2008 – 37.8 percent).

	2009	2008
Debt		
Short-term debt	$ 14,626	$ 4,493
Current portion of long-term debt	591,944	1,363
Long-term debt	408,170	559,412
Convertible debentures	–	16,682
	1,014,740	581,950
Unitholders' equity	1,048,857	957,442
Total capitalization	$ 2,063,597	$ 1,539,392
Debt-to-total-capitalization ratio (%)	49.2	37.8

All of the borrowing facilities have covenants customary for the types of facilities that must be met at the end of each calendar quarter. AltaGas has been in compliance with these covenants each quarter since the issuance of the facilities.

The debt covenants are based on non-GAAP measures that cannot be recalculated from information provided in the Consolidated Financial Statements.

The following table summarizes the Trust's debt covenants for all credit facilities as at December 31, 2009:

Ratios [1]	Debt covenant requirements
Debt-to-capitalization	not greater than 60 percent
Debt-to-EBITDA	not greater than 3.5x
EBITDA-to-interest expense	not less than 2.5x
Debt-to-capitalization (Utility Group)	not greater than 67.5 percent

1 Debt covenant ratios are calculated in accordance with the credit facility agreements including adjustments for business acquisitions and will differ from management's internal calculation due to the definition of certain items in the credit facility agreements.

15. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

In the course of normal operations, the Trust purchases and sells natural gas, natural gas liquids (NGLs) and power commodities and issues short- and long-term debt. The Trust uses derivative instruments to reduce exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates that arise from these activities. The Trust does not make use of derivative instruments for speculative purposes.

Fair Values of Financial Instrumen[illegible]

At December 31, 2009 and 2008, all derivatives, other than those that meet the expected purchase, sale or usage requirements exemption, were carried on the Consolidated Balance Sheets at fair value. The fair value of power, natural gas and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. The calculation of fair value of the interest rate and foreign exchange derivatives used quoted market rates.

The fair value of long-term debt has been estimated based on discounted future interest and principal payments using estimated interest rates. The fair value of the convertible debentures was estimated using a Black-Scholes model.

The carrying amount and fair values of the Trust's financial assets and liabilities were as follows:

Summary of fair values December 31, 2009	Held trading	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Financial assets							
Cash and cash equivalents [1]	$ 3,739	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Short-term investment [1]	19,43[illegible]						[illegible]
Accounts receivable [1]	–	–	189,458	–	–	14,21[illegible]	[illegible]
Restricted cash holdings from customers [1]	–	–	27,22[illegible]				[illegible]
Risk management assets (current)	36,108	30,163	–	–	–	–	66,271
Prepaid expense and other current assets [1]	–	–	1,064	–	–	6,44[illegible]	[illegible]
Risk management assets (non-current)	16,673	1,459					[illegible]
Long-term investments and other assets (note 8)	[illegible]			[illegible]		[illegible]	[illegible]
	$ [illegible]	$ [illegible]	$ [illegible]	[illegible]	$ –	$ [illegible]	$ [illegible]
Financial liabilities							
Accounts payable and accrued liabilities [1]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]
Distributions payable	–	–	–	–	15,110	–	15,11[illegible]
Short-term debt [1]	–	–	–	–	14,626	–	14,[illegible]
Current portion of long-term debt [2]		[illegible]	[illegible]		[illegible]		[illegible]
Customer deposits [1]					[illegible]	–	[illegible]
Risk management liabilities (current)	31,408	[illegible]	[illegible]				[illegible]
Other liabilities [1]	–	–	–	–	14,162	668	[illegible]
Long-term debt [3]	–	–	–	–	[illegible]	[illegible]	[illegible]
Risk management liabilities (non-current)	13,732	[illegible]			–	–	[illegible]
	$ 45,140	$ [illegible]	$ –	$ –	$ [illegible]	$ [illegible]	$ [illegible]

1 Due to the nature and/or short maturity of these financial instruments, the carrying amount approximates the fair value.

2 Fair value of current portion of long-term debt is approximately $591.8 million.

3 Fair value of long-term debt excluding non-financial instruments is approximately $425.7 million.

Summary of fair values December 31, 2008	Held-for-trading	Cash flow hedges	Loans and receivables	Available-for-sale	Other financial liabilities	Non-financial instruments	Total
Financial assets							
Cash and cash equivalents [1]	$ 18,304	$ –	$ –	$ –	$ –	$ –	$ 18,304
Accounts receivable [1]	–	–	214,589	–	–	5,691	220,280
Restricted cash holdings from customers [1]	–	–	24,017	–	–	–	24,017
Risk management assets (current)	36,156	56,686	–	–	–	–	92,842
Prepaid expense and other assets [1]	–	–	1,490	–	–	6,215	7,705
Risk management assets (non-current)	13,114	18,033	–	–	–	–	31,147
	$ 67,574	$ 74,719	$ 240,096	$ –	$ –	$ 11,906	$ 394,295
Financial liabilities							
Accounts payable and accrued liabilities [1]	$ –	$ –	$ –	$ –	$130,724	$ 67,508	$ 198,232
Distributions payable	–	–	–	–	12,943	–	12,943
Short-term debt [1]	–	–	–	–	4,493	–	4,493
Current portion of long-term debt	–	–	–	–	1,363	–	1,363
Customer deposits [1]	–	–	–	–	24,017	–	24,017
Risk management liabilities (current)	34,824	22,599	–	–	–	–	57,423
Other liabilities [1]	–	–	–	–	18,271	3,656	21,927
Long-term debt [2]	–	–	–	–	561,719	(2,307)	559,412
Risk management liabilities (non-current)	10,038	6,707	–	–	–	–	16,745
Convertible debentures	–	–	–	–	16,682	–	16,682
	$ 44,862	$ 29,306	$ –	$ –	$770,212	$ 68,857	$ 913,237

1 Due to the nature and/or short maturity of these financial instruments, the carrying amount approximates the fair value.
2 Fair value of long-term debt is approximately $551 million.

Summary of unrealized gain (loss) on risk management December 31	2009	2008
Natural gas	$ 4,772	$ 5,510
NGL	281	4,997
Power	68	(550)
Heat rate	122	(163)
Interest rate swaps	4,523	(4,896)
Foreign exchange	(6,069)	(6,088)
	[illegible]	$ 10,986

Summary of unrealized gain (loss) and tax expense (recovery) on derivatives designated as cash flow hedges

December 31	[illegible]d gain (loss)	Tax expense (recovery)	2009	Unrealized gain (loss)	Tax expense (recovery)	2008
NGL	$ (2,555)	$ 714	$ (1,841)	$ 35,931	$ (10,352)	$ 25,579
Power	30,622	(8,557)	22,065	5,914	(1,555)	4,359
Bond forward	(2,881)	–	(2,881)	(3,214)	–	(3,214)
Foreign exchange	–	–	–	6,785	(1,967)	4,818
Available-for-sale	4,462	(580)	3.[illegible]	–	–	–
	[illegible]	[illegible]	[illegible]	$ 45,416	$ (13,874)	$ 31,542

Fair Value Hierarchy

The Trust categorizes its financial assets and financial liabilities into one of three levels based on fair value measurements and inputs used to determine the fair value.

Level 1 fair values are based on unadjusted quoted prices in active markets for identical assets or liabilities. Fair value is based on direct observations of transactions involving the same assets or liabilities and no assumptions are used. Included in this category are publicly held shares valued at the closing price as at the balance sheet date.

Level 2 fair values are determined based on inputs other than quoted prices that are observable for the asset or liability. AltaGas uses over-the-counter derivative instruments to manage fluctuations in commodity, interest rate and foreign exchange rates. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, currency exchange and interest rate yield curves. The forward curves used to mark-to-market these derivative instruments are vetted against public sources.

Level 3 fair values are based on inputs for the asset or liability that are not based on observable market data. AltaGas uses valuation techniques when observable market data is not available.

	Level 1	Level 2	Level 3	Total
Financial assets				
Held-for-trading [1]	30,763	52,781	–	83,544
Cash flow hedges	–	31,622	–	31,622
Available-for-sale	13,327	–	–	13,327
Financial liabilities				
Held-for-trading	–	45,140	–	45,140
Cash flow hedges	–	3,551	–	3,551

1 Excludes cash and cash equivalents as carrying amount approximates fair value.

Long-Term Investments a[illegible]

In January 2009 AltaGas purchased common shares of Magma Energy Corp. (Magma) through a private-equity offering for $10.0 million. These shares were classified as available-for-sale. The changes in value for these common shares are reported within OCI, which was $4.5 million as at December 31, 2009. In July 2009, AltaGas purchased additional common shares of Magma as part of its initial public offering. These shares were classified as held-for-trading and included in long-term investments and other assets. As at December 31, 2009, the Trust recognized an unrealized gain of $1.3 million in the Corporate Segment as other revenue.

In October 2009 AltaGas acquired an equity investment in a public company with the acquisition of Utility Group (note 3). The shares are classified as available-for-sale. The changes in value for these common shares are reported within OCI.

[illegible]

For the year ended December 31, 2009 the Trust recognized a realized gain of $6.8 million and unrealized gain of $4.5 million in the Corporate Segment as other revenue.

Market Risk on Financial Instruments

The Trust is exposed to market risk and potential loss from changes in the values of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates.

Commodity Price Risk Management

Natural Gas

The Trust purchases and sells natural gas to its customers. The fixed-price and market-price contracts for both the purchase and sale of natural gas extend to 2014.

The Trust had the following contracts outstanding:

December 31, 2009			Notional volume (GJ)		
Derivative instruments	Fixed price (per GJ)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$4.55 to $10.01	1–61	127,863,433	–	$ 47,598
Commodity forward	$4.51 to $9.825	1–61	–	127,863,433	$ (40,808)

December 31, 2008			Notional volume (GJ)		
Derivative instruments	Fixed price (per GJ)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$2.27 to $10.49	1–59	77,195,070	–	$ 27,209
Commodity forward	$2.27 to $10.73	1–59	–	77,195,070	$ (24,720)

NGL

The Trust entered into a series of swaps to lock in a portion of the volumes exposed to NGL frac spread.

The Trust had the following contracts outstanding:

December 31, 2009			Notional volume		
Product	Fixed price	Period (months)	Sales	Purchases	Fair value
Propane	$0.858 to $1.555 US/gallon	1–12	14,705,000 gallons	–	$ (347)
Butane	$1.100 to $1.870 US/gallon	1–12	4,726,000 gallons	–	$ (231)
WTI	$72.55 to $122.95 US/Bbl	1–12	80,700 Bbls	–	$ 749
USD swaps	$0.995 to $1.154	1–12		$ 38,890	$ 202
Natural gas	$4.79 to $8.88/GJ	1–12	–	3,270,600 GJ	$ (2,375)

December 31, 2008			Notional volume		
Product	Fixed price	Period (months)	Sales	Purchases	Fair value
Propane	$1.380 to $1.800 US/gallon	1–24	36,330,000 gallons	–	$ 40,016
Butane	$1.650 to $2.300 US/gallon	1–24	11,676,000 gallons	–	$ 15,915
WTI	$94.50 to $144.65 US/Bbl	1–24	134,500 Bbls	–	$ 9,531
USD swaps	$0.995 to $1.026	1–24		$ 82,550	$ (17,749)
Natural gas	$7.84 to $9.93/GJ	1–24	–	5,451,000 GJ	$ (11,509)

Power

Under the PPAs AltaGas has an obligation to buy power at agreed terms and prices to December 31, 2020. The Trust sells the power to the Alberta Electric System Operator at market prices and uses swaps and collars to fix the prices over time on a portion of the volumes. AltaGas' strategy is to lock in margins to provide predictable earnings. Certain contracts met the expected purchase, sale or usage requirements exception and have not been included in risk management assets or liabilities. At December 31, 2009 the Trust had no intention to terminate any contracts prior to maturity.

The Trust had the following commodity forward contracts on electrical power outstanding at December 31, 2009 (December 31, 2008 – nil):

December 31, 2009

			[illegible]			
Derivative instruments	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]
Commodity forward	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Commodity forward	$44.75 to $70.36	1–37	–	47,349	$	(1,59

The Trust had the following commodity swaps and collars outstanding:

December 31, 2009

			[illegible]			
Derivative instruments	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]
Swaps and collars	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Swaps and collars	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

December 31, 2008

			Notional volume (MWh)			
Derivative instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases		Fair value
Swaps and collars	$60.50 to $88.00	1–24	2,595,105	–	$	734
Swaps and collars	$56.50 to $75.75	1–108	–	259,520	$	5,207

The Trust had the following heat rate hedges outstanding:

December 31, 2009

			[illegible]			
Derivative instruments	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]
Natural gas (per GJ)	[illegible]	[illegible]	–	[illegible]	[illegible]	[illegible]
Power (per MWh)	[illegible]	[illegible]	[illegible]	–	[illegible]	[illegible]

December 31, 2008

			Notional volume (GJ or MWh)			
Derivative instruments	Fixed price (per GJ or MWh)	Period (months)	Sales	Purchases		Fair value
Natural gas (per GJ)	$6.07	1	–	14,700	$	(5)
Power (per MWh)	$107.50 to $195.50	1	1,225	–	$	29

Interest Rate Risk Management

To hedge against the effects of future interest rate movements, the Trust enters into interest rate swap agreements to fix the interest rate on a portion of its bankers' acceptances issued under credit facilities. The Trust's target is to have approximately 70 to 75 percent of its debt at fixed interest rates.

The Trust had the following interest rate swaps outstanding:

December 31, 2009	Weighted average interest rate	Period (months)		Notional quantity		Fair value
Swaps	2.756%	1–26	$	185,000	$	(282)

December 31, 2008	Weighted average interest rate	Period (months)		Notional quantity		Fair value
Swaps	3.746%	1–15	$	205,000	$	(4,814)

Foreign Exchange Risk Management

To manage the risk of fluctuating cash flows due to variations in foreign exchange rates, the Trust enters into foreign exchange forwards, swaps and options for U.S. dollars (USD) and euros (EUR).

The Trust had the following contracts outstanding:

December 31, 2009	Fixed price	Period (months)		Notional quantity		Fair value
Swaps (USD)	$1.0164 to $1.2215	1–21	$	16,900	$	248

December 31, 2008	Fixed price	Period (months)		Notional quantity		Fair value
Swaps (USD)	$1.0164 to $1.2925	1–21	$	3,273	$	539
Forwards and options (EUR) [1]	$1.470 to $1.5350	4–9	€	62,700	$	12,651

1 Related to the supply and installation agreement with Enercon GmbH to supply and install wind turbines for the Bear Mountain Wind Project. Obligations are denominated in euros.

In 2009 AltaGas entered into a natural gas storage agreement denominated in U.S. dollars resulting in an embedded derivative. The change in value of the contract is recognized in unrealized gain on risk management. The unrealized gain was $87,057 as of December 31, 2009.

Bond Forward

In April 2009 the Trust issued $200 million of senior unsecured MTNs with a maturity date of April 2014. To partially hedge against the risk of rising interest rates, the Trust entered into a $50 million bond forward contract with a Canadian chartered bank in December 2008, to lock in a five-year Government of Canada bond yield of approximately 3.28 percent. The Trust settled the bond forward contract in April 2009, and the $3.4 million payment was recorded in other comprehensive income and is being amortized to interest expense over the term of the MTN.

Sensitivity Analysis

The sensitivity analysis is estimated based on the notional volumes of each commodity, interest rate swap and foreign exchange contract outstanding, taking into consideration future income tax impact.

The following table illustrates potential effects of changes in relevant risk variables on AltaGas' net income and OCI for contracts in place at December 31, 2009:

Factor share	Increase or decrease [1]	Increase or decrease in net income	Increase or decrease in OCI
Alberta electricity average pool prices	$1/MWh	$ –	$ 951
Natural gas spot price (AECO)	$0.50/GJ	758	–
NGL frac spread:			
Propane	$1/Bbl	152	142
Butane	$1/Bbl	81	–
WTI	$1/Bbl	15	43
Natural gas to replace heat value of NGL	$0.50/GJ	–	1,177
Foreign exchange (USD only)	1%	7	275
Interest rate swaps	25 bps	423	–
Foreign exchange	1%	$ 121	$ –

1 Estimated increase or decrease to forward prices or curves.

Credit Risk on Financial Instruments

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract.

AltaGas' credit policy details the parameters used to grant, measure, monitor and report on credit provided to counterparties. AltaGas minimizes counterparty risk by conducting credit reviews on counterparties in order to establish specific credit limits on clients, both prior to providing products or services and on a recurring basis. In addition, most contracts include credit mitigation clauses that allow AltaGas to obtain financial or performance assurances from counterparties under certain circumstances. AltaGas provides an allowance for doubtful accounts in the normal course of its business.

The Trust's maximum credit exposure consists primarily of the carrying value of the non-derivative financial assets and the fair value of derivative financial assets. At December 31, 2009 AltaGas had no concentration of credit risk with a single counterparty.

The Trust had the following past due and impaired receivables:

December 31, 2009 **Accounts receivable**	2009	Receivables impaired	Receivables by period and not impaired Less than 30 days	31–60 days	61–90 days	Over 90 days
Trade receivable	$ 191,797	$ 2,167	$ 170,572	$ 8,379	$ 2,841	$ 7,838
Other receivable	14,043	–	9,974	–	161	[illegible]
Allowance for credit losses	[illegible]	[illegible]				
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Allowance for credit losses

Allowance for credit losses, beginning of year	$ 1,908
Impairment expense	[illegible]
Allowance for credit losses, end of year	[illegible]

December 31, 2008 **Accounts receivable**	2008	Receivables impaired	Receivables by period and not impaired Less than 30 days	31–60 days	61–90 days	Over 90 days
Trade receivable	$ 213,959	$ 1,908	$ 193,012	$ 9,887	$ 3,029	$ 6,123
Other receivable	8,229	–	7,672	–	194	363
Allowance for credit losses	(1,908)	(1,908)	–	–	–	–
	$ 220,280	$ –	$ 200,684	$ 9,887	$ 3,223	$ 6,486

Allowance for credit losses

Allowance for credit losses, beginning of year	$ 1,765
Impairment expense	143
Allowance for credit losses, end of year	$ 1,908

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. The Trust manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations. The Trust's objective is to maintain its investment-grade ratings to ensure it has access to debt and equity funding as required (note 15).

At December 31, 2009 the Trust had the following contractual maturities with respect to non-derivative financial liabilities:

	Total	Payments due by period Less than 1 year	1–3 years	4–5 years	After 5 years
Short-term debt	$ 14,626	$ 14,626	$ –	$ –	$ –
Current portion of long-term debt	591,944	591,944	–	–	–
Long-term debt [1,2]	411,380	–	104,858	206,522	100,000
	$ 1,017,950	$ 606,570	$ 104,858	$ 206,522	$ 100,000

1 Comprising operating loans, MTNs and capital lease obligations excluding deferred financing costs (note 10).
2 Credit facilities maturing within the next 12 months are expected to be refinanced on a long-term basis.

16. UNITHOL[illegible]

December 31		2008
Unitholders' capital (note 17)	$ 982,662	$ 850,992
Contributed surplus (notes 4, 11 and 18)	5,621	4,261
Accumulated earnings	815,045	673,736
Convertible debentures	–	1,600
Warrants	4,500	4,500
Accumulated dividends	(41,114)	(41,114)
Accumulated unitholders' distributions declared [1]	(709,058)	(538,227)
Distributions of common shares of Utility Group	(29,848)	(29,848)
Transition adjustment resulting from adopting new financial instruments accounting standards	(176)	–
Accumulated other comprehensive income	21,225	31,542
	[illegible]	$ 957,442

1 Accumulated unitholders' distributions paid by the Trust as at December 31, 2009 were $694.0 million (as at December 31, 2008 – $525.3 million).

The Trust is authorized to issue:

- An unlimited number of trust units redeemable for cash at the option of the holder;
- An unlimited number of AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2014 the exchange is at the option of the unitholder at any time, and at the option of the Trust should the number of AltaGas LP #1 units outstanding fall below 750,000. After May 1, 2014 the exchange is at the option of either the Trust or the unitholder; and
- An unlimited number of AltaGas Holding Limited Partnership No. 2 (AltaGas LP #2) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2009 the exchange was at the option of the unitholder at any time, and at the option of the Trust should the number of AltaGas LP #2 units outstanding fall below 1,000,000. Since May 1, 2009 the exchange is at the option of either the Trust or the unitholder.

Trust units issued and outstanding	Number	Amount
December 31, 2007	56,057,438	$ 493,866
Units issued for cash on exercise of options	2,150	55
Units issued under DRIP [1]	1,635,937	34,612
Units issued for exchangeable units	60,890	859
Units issued on business acquisition	7,553,174	194,645
Units issued on conversion of convertible debentures	53,439	1,843
Units issued on public offering (net of $5.2 million of issuance costs)	4,398,750	110,077
December 31, 2008	69,761,778	$ 835,957

Exchangeable units issued and outstanding		
December 31, 2007 issued by AltaGas LP #1	2,040,456	$ 11,678
AltaGas LP #1 units redeemed for Trust units	(60,890)	(859)
Units issued on business acquisition	163,607	4,216
December 31, 2008	2,143,173	15,035
Issued and outstanding at December 31, 2008	71,904,951	$ 850,992

Trust units issued and outstanding	Number of units	Amount
December 31, 2008	69,761,778	$ 835,957
Units issued for cash on exercise of options	71,750	1,246
Units issued under DRIP [1]	2,236,266	34,169
Units issued for exchangeable units	59,517	892
Units issued on conversion of convertible debentures	2,637	71
Units issued on public offering (net of $5.4 million of issuance costs and $0.9 million tax benefit) [2]	6,100,000	96,184
December 31, 2009	78,231,948	$ 968,519

Exchangeable units issued and outstanding	Number of units	Amount
December 31, 2008 issued by AltaGas LP #1	2,143,173	$ 15,035
AltaGas LP #1 units redeemed for Trust units	(59,517)	(892)
December 31, 2009	2,083,656	14,143
Issued and outstanding at December 31, 2009	80,315,604	$ 982,662

1 Distribution Reinvestment Program.
2 Net proceeds on issuance of units will not tie to the units issued due to non-cash items, including tax benefits.

Weighted average units outstanding [1]	2009	2008
Number of units – basic	78,539,800	68,812,654
Dilutive equity instruments [2]	830,847	890,744
Number of units – diluted	79,370,647	69,703,398

1 Includes exchangeable units.
2 Includes options, convertible debentures and warrants.

The Trust has an employee unit option plan under which employees and directors are eligible to receive grants. At December 31, 2009, 10 percent of units outstanding were reserved for issuance under the plan. As at December 31, 2009 options granted under the plan generally had a term of 10 years until expiry and vested no longer than over a four-year period.

At December 31, 2009 outstanding options were exercisable at various dates within the next nine years. As at December 31, 2009 the unexpensed fair value of unit option compensation cost associated with future periods was $0.7 million (December 31, 2008 – $0.6 million).

The following table summarizes information about the Trust's unit options:

	Options outstanding			
	2009		2008	
	Number of options	Exercise price [1]	Number of options	Exercise price [1]
Unit options outstanding, beginning of year	2,972,250	$ 20.33	1,310,400	$ 26.36
Granted	1,024,500	18.04	1,882,250	16.84
Exercised	(71,750)	12.94	(2,150)	17.17
Expired	(117,750)	20.30	(218,250)	26.42
Unit options outstanding, end of year	3,807,250	$ 19.86	2,972,250	$ 20.33
Unit options exercisable, end of year	1,194,398	$ 23.48	602,326	$ 25.91

1 Weighted average.

The following table summarizes the employee unit option plan as at December 31, 2009:

	Options outstanding			Options exercisable	
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
$5.00 to $15.25	1,301[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
$15.26 to $25.08	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
$25.09 to $29.15	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]	[illegible]	1,194,398	$ 23.[illegible]

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	[illegible]	2008
Risk-free interest rate (%)	3.35	3.43
Expected life (years)	10	10
Expected volatility (%)	24.58	23.81
Annual distribution per unit ($)	2.15	2.10

In 2004 AltaGas implemented a unit-based compensation plan, which awards phantom units to certain employees. Beginning in 2008, all employees were eligible to receive phantom units. The phantom units are valued on distributions declared and the trading price of the Trust's units. The units vest on a graded vesting schedule. The compensation expense recorded in 2009 in respect of this plan was $7.2 million (2008 – $5.5 million). As at December 31, 2009 the unexpensed fair value of unit-based compensation costs associated with future periods was $26.4 million (December 31, 2008 – $18.4 million).

18. CONTRIBUT[illegible]

	[illegible]	2008
Balance, beginning of year	$ 4,261	$ 3,875
Amortization of unit options	376	431
Exercise of unit options	(318)	(18)
Cancellation of unit options	(213)	(27)
Other adjustments [1]	1,515	–
Balance, end of year	$ 5,621	$ 4,261

1 Includes equity portion of convertible debentures redeemed in September 2009 of $1.6 million (note 11).

19. NE[illegible]

The following table summarizes the computation of net income per unit:

Years ended December 31	2009	2008
Numerator:		
Numerator for basic net income per unit	$ 141,309	$ 163,571
Numerator for diluted net income per unit	$ 141,998	$ 164,567
Denominator:		
Weighted average number of units	78,540	68,813
Dilutive equity instruments [1]	831	891
Denominator for diluted net income per unit	79[illegible]	69,704
Basic net income per unit	$ 1.80	$ 2.38
Diluted net income per unit	$ 1.79	$ 2.36

1 Includes options, convertible debentures and warrants.

Future minimum lease payments under operating leases for office space, office equipment and automotive equipment at December 31, 2009 are estimated as follows:

2010	$	4,985
2011		4,386
2012		3,602
2013		886
2014		601
	$	14,460

In 1999 the Trust acquired an agreement to purchase natural gas from specific reserves for $0.05/Mcf for the life of the reserves. The production from these reserves was 841 Mcf/d in 2009 (2008 – 1,239 Mcf/d).

In 2007 AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain Wind Park. The Trust has an obligation to pay a minimum of $0.5 million over the next 12 years.

In 2009 AltaGas entered into a 20-year storage contract at the Dawn Hub in southwest Ontario. The Trust is obligated to pay approximately $3.3 million per annum over the term of the contract for storage services.

In 2009 AltaGas entered into various purchase agreements with respect to Ante Creek and Pouce Coupe gas processing facilities. In 2010 the Trust is obligated to pay approximately $1.5 million and $1.6 million, respectively, to increase processing capacity at these facilities.

The net change in the following non-cash working capital items increased (decreased) cash flows from operations as follows:

Years ended December 31		2009 [1]		2008 [1]
Accounts receivable	$	41,744	$	4,803
Inventory		(626)		(645)
Other current assets [2]		200		(4,491)
Regulatory assets		(1,774)		–
Accounts payable and accrued liabilities		(75,057)		(7,878)
Customer deposits		6,661		(352)
Deferred revenue		(2,777)		1,059
Other current liabilities		(7,096)		12,606
		[illegible]		5,102
Add back:				
Increase (decrease) in capital costs payable		20,996		(15,993)
Net change in non-cash working capital related to operations	$	(17,729)	$	(10,891)

1 Specific line items may not agree with the net change in the Consolidated Balance Sheets due to acquisition.
2 Excludes note receivable of $6.5 million included in investing activities in 2008.

The following cash payments have been included in the determination of earnings:

Years ended December 31		2009		2008
Interest paid	$	32,328	$	24,023
Income taxes paid (received)	$	(89)	$	2,577

Defined Contribution

On July 1, 2005 AltaGas implemented a defined contribution (DC) pension plan for substantially all employees. The DC plan replaced the Group RRSP as AltaGas' primary employer-sponsored retirement arrangement.

The net pension expense recorded for the DC pension plan was $2.3 million for the year ended December 31, 2009 (2008 – $1.7 million).

Effective August 25, 2004 the liability for a defined benefit, non-contributory pension plan in respect of nine Trust employees for pre-AltaGas pensionable service was assumed under Part II of the Salaried Employees' Pension Plan as a result of an acquisition. No future service accrues under this plan.

Plan contributions for Parts II, III and IV of the Salaried Employees' Pension Plan in 2009 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2008 based on a report dated April 29, 2009, and plan contributions for 2008 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2005 based upon a report dated March 29, 2006.

As at December 31, 2009 the accrued benefit obligation of the Trust for this plan was $2.2 million (December 31, 2008 – $1.9 million). At December 31, 2009 the plan had an accrued benefit asset recognized in the Consolidated Financial Statements of $3,000 (December 31, 2008 – $10,000).

In 2008 the Trust assumed two defined benefit pension plans with the acquisition of Taylor (note 3). These plans are in relation to the unionized employees at the Younger Extraction Plant (Younger) and certain employees at the Harmattan Complex (Harmattan). Plan contributions for the Younger pension plan and Harmattan pension plan during 2009 were made in accordance with an actuarial valuation for funding purposes as at December 31, 2006 and December 31, 2008, respectively. As at December 31, 2009 the accrued benefit obligation of the Trust for these plans was $9.0 million (December 31, 2008 – $7.7 million). At December 31, 2009 these plans had an accrued benefit liability recognized in the Consolidated Financial Statements of $0.8 million (December 31, 2008 – $1.1 million).

In 2009 the Trust assumed two defined benefit non-contributory pension plans in the acquisition of Utility Group (note 3). The plans are in relation to substantially all full-time employees of AUI. Plan contributions for the AUI pension plans during 2009 were made in accordance with actuarial valuations for funding purposes as at September 30, 2008 based on reports dated March 31, 2009. As at December 31, 2009 the accrued benefit obligation of the Trust for these plans was $19.0 million (December 31, 2008 – nil). At December 31, 2009 the plans had accrued benefit liabilities recognized in the Consolidated Financial Statements of $1.4 million (December 31, 2008 – nil).

For the year ended December 31, 2009 the net pension cost for all defined benefit plans was $0.8 million (2008 – $0.4 million).

Effective July 1, 2005 the Trust instituted a non-registered, defined benefit retirement plan that provides defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. In 2009, the Trust assumed the liability recorded for the SERP held by Utility Group (note 3). As at December 31, 2009 the accrued benefit obligation of the Trust for this plan was $6.4 million (December 31, 2008 – $3.6 million). At December 31, 2009 the plan had an accrued benefit liability recognized in the financial statements of $6.2 million (December 31, 2008 – $3.7 million).

The SERP benefits will be paid from the general revenue of AltaGas as payments come due. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

For the year ended December 31, 2009 the net pension expense related to the SERP was $1.2 million (2008 – $1.7 million).

In 2008 the Trust assumed two post-retirement benefit plans for the unionized employees at Younger and Harmattan. Benefits provided to retired employees are limited to the payment of life insurance and health insurance premiums.

In 2009 the Trust assumed a post-retirement benefit plan for certain employees of AUI providing benefits such as life insurance and health care. These other benefit plans are not funded.

For the year ended December 31, 2009 the net benefit cost for these plans was $0.2 million (2008 – $0.1 million).

The estimates for health care benefits takes into consideration increased health care benefits due to aging and cost increases in the future. The assumed initial health care cost trend rate used to measure the expected cost of benefits is 7.83 percent and the ultimate trend rate is 4.50 percent, which is assumed to be achieved by 2029.

The following table summarizes the details of the defined benefit plans, including the SERP and post-retirement plans:

	Defined benefit 2009	Post-retirement benefits 2009	Defined benefit 2008	Post-retirement benefits 2008
Accrued benefit obligation				
Balance, beginning of year	$ 13,146	$ 563	$ 4,968	$ –
Assumed through acquisition [1,2]	16,910	1,217	10,154	734
Actuarial gain	3,673	617	(3,588)	(235)
Current service cost	2,261	93	1,575	37
Member contributions	–	–	102	–
Past service cost	–	–	294	–
Interest cost	2,249	136	844	41
Benefits paid	(1,628)	(55)	(1,203)	(14)
Balance, end of year	36,611	2,571	13,146	563
Plan assets				
Fair value, beginning of year	8,763	–	1,586	–
Assumed through acquisition [1,2]	14,542	–	8,345	–
Actual loss on plan assets	4,978	–	(1,538)	–
Employer contributions	2,280	55	1,471	14
Member contributions	95	–	102	–
Benefits paid	(1,628)	(55)	(1,203)	(14)
Expected plan expenses	(342)	–	–	–
Fair value, end of year	28,688	–	8,763	–
Funded deficit	(7,923)	(2,571)	(4,383)	(563)
Unamortized transitional obligation	179	181	–	–
Unamortized past service costs	625	–	(810)	–
Unamortized net actuarial loss	1,511	137	389	(235)
Accrued benefit liability recognized in the financial statements	$ (5,608)	$ (2,253)	$ (4,804)	$ (798)

	Defined benefit 2009	Post-retirement benefits 2009	Defined benefit 2008	Post-retirement benefits 2008
Significant actuarial assumptions used as at December 31				
Discount rate (%)	6.20–7.10	6.50–6.70	7.25	7.25
Expected long-term rate of return on plan assets (%)	6.75–7.75	6.75	6.75–7.25	7.25
Rate of compensation increase (%)	4.00–5.50	4.00	3.50–4.00	4.00
Average remaining service life of active employees (years)	14.8	10.1	12.9	9.2
Net benefit plan expense for the year				
Current service cost and expenses	$ 1,519	$ 43	$ 1,575	$ 37
Interest cost	1,262	62	844	41
Actual gain (loss) on plan assets	(2,362)	–	1,538	–
Actuarial gain (loss) on accrued benefit obligation	2,380	209	(3,588)	(235)
Costs arising in the year	2,799	314	369	(157)
Differences between costs arising in the year and costs recognized in the year in respect of				
Actuarial gain (loss) on plan assets	1,498	–	(2,197)	–
Plan amendments	1	–	–	–
Actuarial gain (loss) on accrued benefit obligation	(2,414)	(231)	3,588	235
Amortization of past service costs	77	–	371	–
Transitional obligations	11	7	–	–
Net periodic benefit plan costs recognized	$ 1,972	$ 90	$ 2,131	$ 78

1 Includes the AUI plan acquired in the acquisition of Utility Group (note 3) in 2009.
2 Includes the Younger and Harmattan plans acquired in the acquisition of Taylor (note 3) in 2008.

The assets are invested under balanced fund mandates with a broad mix of fixed income, Canadian equity and foreign equity investments. The collective investment mixes for the plans are as follows as at December 31, 2009:

	Percentage of plan assets
Cash and short-term equivalents	2.4%
Canadian equities	33.78%
Foreign equities	27.74%
Fixed income	36.08%
	100.00%

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in the assumed health care trend rates would have the following effects for 2009:

	Increase	**Decrease**
Service and interest costs	7	(6)
Accrued benefit obligation	310	(249)

On October 8, 2009 AltaGas acquired all of the outstanding common shares of Utility Group (note 3) and therefore consolidated the operating results of the Utility Group with the results of the Trust. All intercompany transactions have been eliminated on consolidation.

In the normal course of business, the Trust and its affiliates transact with related parties. These transactions are recorded at their exchange amounts and are as follows:

Years ended December 31	2009	2008
Fees for administration, management and other services paid by		
Utility Group to the Trust [1]	[illegible]	$ 219
The Trust to Utility Group [1]	[illegible]	$ 4
Natural gas sales by the Trust to Utility Group subsidiaries [1]	[illegible]	$ 96,457
Fees for operating services paid by Utility Group subsidiaries [1]	[illegible]	$ 427
Transportation services provided by Utility Group subsidiaries [1]	[illegible]	$ 491
Office space and furniture rental payments made by the Trust to a corporation owned by an employee	$ 90	$ 88

1 Includes transactions up to the date of acquisition of Utility Group (note 3).

The resulting amounts due from and to related parties are non-interest-bearing and are related to transactions in the normal course of business.

The Trust's proportionate interest in its joint venture arrangements is summarized as follows:

	[illegible]	2008
Proportionate share of operating income for the years ended December 31		
Revenues	$ 238,176	$ 402,006
Expenses	193,807	290,677
	[illegible]	$ 111,329
Proportionate share of net assets at December 31		
Current assets	$ 31,304	$ 39,517
Capital assets	299,213	283,426
Energy services arrangements, contracts and relationships	82,284	88,893
Long-term investments and other assets	14	1
Current liabilities	(15,644)	(30,622)
Other long-term liabilities	(1,660)	(912)
	[illegible]	$ 380,303
Proportionate share of cash flows for years ended December 31		
Operating activities	$ 61,613	$ 121,015
Investing activities	(18,497)	(214,624)
Financing activities	[illegible]	96,094
	[illegible]	$ 2,485

In first quarter 2009 AltaGas entered into a non-monetary transaction with a third party in which it exchanged B.C. Renewable Energy Certificates (RECs) for verified emission offsets that were generated in Alberta. The RECs will be created through the generation of power at the Bear Mountain Wind Park between 2009 and 2011. The verified emission offsets received by AltaGas were used to offset the costs to comply with Alberta's Specified Gas Emitters Regulation in 2009.

The contingent liability related to the Sundance B Unit 4 facility outage in mid-December 2008 due to the failure of an induced fan was settled in August 2009. The terms of the settlement are confidential. No contingent liabilities are outstanding related to power outages.

Certain comparative figures have been reclassified to conform to the current financial presentation.

On January 1, 2010 AltaGas issued 180,433 units on exercise of special warrants that were originally issued in February 2008 on a one-for-one basis at $24.94 per special warrant.

On February 2, 2010 AltaGas offered to acquire all the outstanding common shares of Landis Energy Corporation (Landis) in exchange for cash of $0.80 per common share. The acquisition is valued at approximately $22 million and, if successful, will be funded through AltaGas' existing credit facilities. The offer is subject to certain conditions, including its acceptance by the holders of at least two-thirds of the outstanding common shares of Landis and regulatory approval. The offer is currently due to expire on March 10, 2010.

29. SEGMENTED INFORMATION

AltaGas is an integrated energy trust with a portfolio of assets and services used to move energy from the source to the end user. The majority of the transactions among the reporting segments are recorded at the market price of the commodities, and the remainder is at the exchange amount. In accordance with the CICA Handbook Section 1700, for the year ended December 31, 2009, AltaGas has changed the composition of its reportable segments as a result of modifications and growth of the enterprise. Comparative periods have been restated based on the current reportable segments. The following describes the Trust's three reporting segments:

Gas	• NGL processing and extraction plants • transmission pipelines to transport natural gas and NGL • natural gas gathering lines and processing facilities • energy consulting and sale of natural gas and electricity • natural gas storage facilities • regulated natural gas distribution assets
Power	• coal-fired and gas-fired power output under power purchase arrangements and other agreements • gas-fired power plants • wind and run-of-river power plants
Corporate	• the costs of providing corporate services and general corporate overhead, investments in public and private entities, corporate assets and the effects of changes in the fair value of risk management contracts

The following tables show the composition by segment:

Year ended December 31, 2009	[illegible] Segment	[illegible] Segment	[illegible] Segment	[illegible] elimination	Total
Revenue	$ 1,142,411	$ 188.508	$ 14,919	$ (81,270)	$ 1.264.568
Unrealized gain on risk management	–	–	3,697	–	3,697
Cost of sales	(802,262)	(86,280)	–	76,854	(811,688)
Operating and administrative	(166,433)	(6,069)	(40,133)	4,416	(208,219)
Amortization	(63,427)	(8,167)	(2,527)	–	(74,121)
Foreign exchange gain	–	–	(1)	–	(1
Interest expense	–	–	(31,759)	–	(31,759)
Income (loss) before income taxes	$ 110,289	$ 87,992	$ (55,804)	–	$ 142,477
Net additions to					
Capital assets [1]	$ 323,779	$ 159,544	$ 3,073	–	$ 486,396
Long-term investment and other assets [2]	$ (12,300)	$ (367)	$ 24,410	–	$ 11,743
Goodwill	$ 201,728	–	–	–	$ 201,728
Segmented assets	$ 2,053,177	$ 425,899	$ 150,020	–	$ 2,629,096

1 Difference in timing of cash flows, non-cash transactions and assets acquired in business acquisitions (note 3), recorded as acquisition of long-term investment on statement of cash flow of $245,397.

2 Difference in timing of cash flows, non-cash transactions and assets acquired in business acquisitions (note 3), recorded as acquisition of long-term investment on statement of cash flow of $195,553.

Year ended December 31, 2008	Gas Segment	Power Segment	Corporate Segment	Intersegment elimination	Total
Revenue	$ 1,643,187	$ 223,510	$ 1,882	$ (62,770)	$ 1,805,809
Unrealized gain on risk management	–	–	10,986	–	10,986
Cost of sales	(1,308,989)	(94,518)	–	63,189	(1,340,318)
Operating and administrative	(173,230)	(3,715)	(44,136)	(419)	(221,500)
Amortization	(57,306)	(7,436)	(2,236)	–	(66,978)
Foreign exchange gain	–	–	1,369	–	1,369
Interest expense	–	–	(27,399)	–	(27,399)
Income (loss) before income taxes	$ 103,662	$ 117,841	$ (59,534)	–	$ 161,969
Net additions to					
Capital assets [1]	$ 664,847	$ 136,523	$ 6,592	–	$ 807,962
Energy services arrangements, contracts and relationships	$ 53,000	–	–	–	$ 53,000
Long-term investment and other assets [2]	–	$ 713	$ (47,479)	–	$ (46,766)
Goodwill	$ 143,840	–	–	–	$ 143,840
Segmented assets	$ 1,708,335	$ 268,474	$ 155,444	–	$ 2,132,253

1 Difference in timing of cash flows, non-cash transactions and assets acquired in business acquisitions (note 3), recorded as acquisition of long-term investment on statement of cash flow of $679,652.

2 Difference in timing of cash flows, non-cash transactions and assets acquired in business acquisitions (note 3), recorded as acquisition of long-term investment on statement of cash flow of $358,259.

10–Year Review of Financial and Operating Information

($ millions unless otherwise indicated)		2009	2008	2007
Income Statement	Revenue	1,268.3	1,816.8	1,428.4
	Net revenue [1]	456.6	476.5	324.0
	EBITDA [1]	248.4	256.4	173.7
	Operating Income [1]			
	Gas	110.3	103.6	59.3
	Power	88.0	117.9	94.6
	Corporate	(24.1)	(33.5)	(27.3)
		[illegible]	188.0	126.6
	Net income	141.3	163.6	108.8
	Net income per basic unit	$ 1.80	$ 2.38	$ 1.90
	EBITDA per basic unit [1]	$ 3.16	$ 3.73	$ 3.03
Cash Flow	Funds from operations [1]	202.3	216.8	162.9
	Funds from operations per basic unit [1]	$ 2.58	$ 3.15	$ 2.84
	Distributions/dividends per unit declared [2]	$ 2.16	$ 2.125	$ 2.065
Balance Sheet	Capital assets	1,857.1	1,436.7	682.3
	Energy service arrangements, contracts and relationships	128.9	138.9	95.7
	Total assets	2,629.1	2,132.3	1,172.7
	Short-term debt	14.6	4.5	3.6
	Long-term debt	1,000.1	560.8	217.2
	Unitholders' equity	1,048.9	957.4	584.7
Unit Data (millions)	Units outstanding at year-end	80.3	71.9	58.1
	Weighted average units outstanding for the year (basic)	78.5	68.8	57.4
Ratios (%)	Return on average equity	13.6	19.6	19.8
	Return on average invested capital	10.0	13.6	16.2
	Debt as a percentage of total capitalization	49.2	37.8	27.4
Gas	Extraction inlet capacity (Mmcf/d) [3]	1,594	1,594	554
	Extraction ethane volumes (Bbls/d) [4]	26,817	24,795	13,355
	Extraction NGL volumes (Bbls/d) [4]	13,236	12,242	6,752
	Total extraction volumes (Bbls/d) [4]	40,053	37,037	20,108
	Frac spread – realized ($/Bbl) [4,5]	23.46	26.97	21.38
	Frac spread – average spot price ($/Bbl) [4,5]	19.51	28.79	22.48
	Transmission volumes (Mmcf/d) [4,6]	324	379	407
	Processing capacity (gross Mmcf/d) [3]	1,172	1,172	1,023
	Processing throughput (gross Mmcf/d) [4]	453	541	527
	Processing capacity utilization (%) [3]	39	46	52
	Natural gas deliveries – end-use (PJ) [7]	6.62	–	–
	Natural gas deliveries – transportation (PJ) [7]	0.55	–	–
	Service sites [3]	72 717	–	–
	Degree day variance (%) [9]	9.9	–	–
	Energy management service contracts [3]	1,748	1,711	1,466
	Average gas volumes marketed (GJ/d) [4,9]	354,513	302,392	388,217
Power	Volume of power sold (GWh) [3]	2,726	2,623	2,661
	Price received on the sale of power ($/MWh) [4]	68.97	84.51	68.59
	Alberta Power Pool price ($/MWh) [4]	47.84	89.95	66.84

1. Non–GAAP financial measure. See discussion on page 33. 2. Distributions declared do not include the November 2005 and August 2007 special distributions of AltaGas Utility Group Inc. shares. 3. As at December 31. 4. Annual average. 5. Indicative frac spread or NGL margin, expressed in dollars per barrel of NGL and derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price. 6. Excludes NGL pipeline volumes.

	2006	2005	2004	2003	2002	2001	2000
	1,362.6	1,502.3	864.6	710.6	492.7	489.8	506.7
	318.9	296.9	250.4	217.3	169.9	135.0	116.3
	173.1	155.5	133.4	121.9	94.8	69.9	57.0
	63.4	66.3	55.8	29.5	33.8	43.4	36.9
	90.9	48.7	35.8	31.6	26.1	–	–
	(27.6)	(6.9)	–	–	–	–	–
	126.7	108.1	91.6	61.1	59.9	43.4	36.9
	114.5	90.3	65.8	38.3	29.4	19.2	17.6
	$2.06	$1.67	$1.33	$0.84	$0.70	$0.50	$0.46
	$3.12	$2.88	$2.70	$2.68	$2.24	$1.83	$1.50
	161.7	129.0	108.6	90.2	70.8	50.2	40.5
	$2.91	$2.39	$2.20	$1.98	$1.67	$1.31	$1.06
	$1.995	$1.85	$1.31	$0.38	$0.28	$0.18	–
	677.9	645.4	746.7	677.9	663.4	521.0	453.0
	103.3	110.9	113.1	101.0	107.0	112.2	–
	1,109.6	1,068.3	1,108.6	919.3	904.9	721.1	581.1
	–	2.7	7.0	4.5	50.6	100.0	–
	265.5	266.3	352.5	392.4	368.9	283.9	216.9
	529.4	478.6	483.5	363.3	338.6	261.9	250.6
	56.4	54.6	53.2	45.7	45.2	38.5	38.2
	55.5	54.0	49.4	45.5	42.3	38.2	38.1
	22.7	18.4	15.7	10.9	9.8	7.3	7.0
	16.3	13.0	11.6	11.1	9.3	8.7	8.6
	33.4	36.0	42.6	52.2	55.3	58.5	45.6
	554	539	539	349	349	219	211
	13,132	13,155	8,602	4,056	1,425	1,063	1,159
	6,564	6,202	4,834	3,519	1,974	1,555	2,210
	19,696	19,357	13,436	7,575	3,399	2,618	3,369
	18.47	9.31	10.51	6.23	6.35	–	–
	18.47	9.31	10.51	6.23	6.35	–	–
	400	432	432	403	106	47	36
	1,021	962	913	861	842	768	712
	555	563	560	520	492	489	418
	54	60	61	61	63	65	61
	–	10.50	14.70	14.70	14.70	13.65	14.70
	–	9.45	11.55	10.50	8.40	8.40	7.35
	–	61,447	60,430	59,543	58,499	57,542	56,692
	–	(1.4)	2.6	6.9	7.8	(3.4)	6.5
	1,394	1,243	427	–	–	–	–
	327,057	312,272	174,337	–	–	–	–
	2,878	3,466	3,481	3,266	2,669	–	–
	69.26	54.59	48.77	47.56	41.27	–	–
	80.48	70.19	54.54	62.98	43.85	–	–

7. 2009 deliveries reflect Utility Group deliveries as of October 8, 2009, when the Trust obtained control and 100 percent of Heritage Gas deliveries as of November 18, 2009. Excludes Inuvik Gas Ltd. for all periods; excludes Heritage Gas Limited for all periods prior to 2009. 8. Variance from 20-year average – positive variances are favourable. 9. Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

Unitholder Information

2009 Distribution History

Ex-Distribution Date	Record Date	Payment Date	Amount
January 22, 2009	January 26, 2009	February 17, 2009	$0.18
February 23, 2009	February 25, 2009	March 16, 2009	$0.18
March 23, 2009	March 25, 2009	April 15, 2009	$0.18
April 23, 2009	April 27, 2009	May 15, 2009	$0.18
May 21, 2009	May 25, 2009	June 15, 2009	$0.18
June 23, 2009	June 25, 2009	July 15, 2009	$0.18
July 23, 2009	July 27, 2009	August 17, 2009	$0.18
August 21, 2009	August 25, 2009	September 15, 2009	$0.18
September 23, 2009	September 25, 2009	October 15, 2009	$0.18
October 22, 2009	October 26, 2009	November 16, 2009	$0.18
November 23, 2009	November 25, 2009	December 15, 2009	$0.18
December 23, 2009	December 29, 2009	January 15, 2010	$0.18
Total 2009 Cash Distribution Declared			$2.16

Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan (DRIP or the plan)

AltaGas Income Trust offers a Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan for eligible holders of Trust units and limited partnership units that are exchangeable into Trust units (Exchangeable Units).

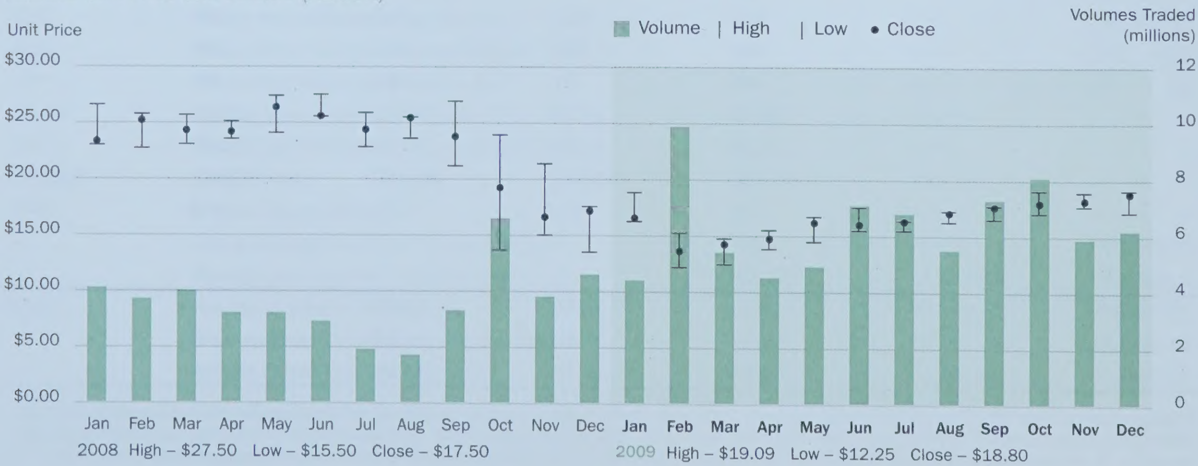
The plan provides unitholders with a convenient and economical way to maximize their investment in AltaGas by providing the opportunity to:

- Reinvest cash distributions into Trust units at a 5 percent discount to the average market price, under the distribution reinvestment component of the plan; or
- Receive a 2 percent premium cash distribution, under the premium distribution component of the plan. AltaGas has suspended the Premium component of the plan. While the Premium component of the plan is suspended, participants will continue to receive regular cash distributions.
- Eligible unitholders may also make optional trust unit purchases at the weighted average market price.

Registered unitholders who are eligible and wish to participate in the plan must enroll directly with Computershare Trust Company of Canada, while beneficial unitholders should contact their broker, investment dealer, financial institution or other nominee that holds their units, in order to enroll.

Complete details on the DRIP are available on the AltaGas Website at www.altagas.ca.

AltaGas Unit Price and Volume (ALA.UN)



Corporate Information

Management Team

David W. Cornhill
Chairman and Chief Executive Officer

Richard M. Alexander
President and Chief Operating Officer

Deborah S. Stein
Vice President Finance
and Chief Financial Officer

Massimiliano Fantuz
Executive Vice President

David R. Wright
Executive Vice President Strategy
and Corporate Development

Gregory A. Aarssen
Vice President Corporate Affairs

Nancy A. Anderson
Vice President
Renewable Energy – Wind

Jeremy R. Baines
Vice President and Treasurer

James B. Bracken
Senior Vice President
Major Projects

Douglas H. Brown
Divisional Vice President
Renewable Energy – Hydro

Dennis A. Dawson
Vice President General Counsel
and Corporate Secretary

Michael J. Kilby
Divisional Vice President
Gas Services

Bradley G.H. Mattson
Vice President
and Corporate Controller

Patricia M. Newson
President
AltaGas Utility Group

Marilyn A. Pfaefflin
Divisional Vice President
Transmission

Kent E. Stout
Vice President
Corporate Resources

William C. Swan
Divisional Vice President
Energy Management

Randy W. Toone
Divisional Vice President
Field Gathering and Processing
and Energy Services

David R. Tulk
Divisional Vice President
Extraction and Transmission

Auditors

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Calgary, Alberta, Canada

Transfer Agent

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Calgary, Alberta, Canada

Toll-free: 1-800-564-6253
Email: service@computershare.com

Investors are encouraged to contact Computershare for information concerning their security holdings.

Stock Exchange Listing

Toronto Stock Exchange: ALA.UN

Annual Meeting

The annual meeting will be held at 3:00 p.m. MDT on Thursday, June 3, 2010 at The Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta.

Investor Relations

For investor relations enquiries, please contact:
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Definitions

Bbls/d	barrels per day
Bcf	billion cubic feet
bps	basis points
GJ	gigajoule
GJ/d	gigajoule per day
GWh	gigawatt-hour
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
NGLs	natural gas liquids
PJ	petajoule

Design and production Karo Group
Photography Gary Campbell, page 2 photo: Cambria Gordon
Printed by McAra

The paper selection preserves 39 trees, saves 16,516 gallons of wastewater flow and conserves 27,540,000 BTUs of energy.

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